Canadian Upstream Oil & Gas Industry Profitability

Historical Review and Future Perspectives

Prepared for
the
Canadian Petroleum Association
and the
Independent Petroleum Association of Canada

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EXECUTIVE SUMMARY

SUMMARY OF MAJOR CONCLUSIONS AND KEY IMPLICATIONS

This report was prepared for the Canadian Petroleum Association and the Independent Petroleum Association of Canada. The purpose was to have an independent assessment of profitability in the upstream sector of the Canadian oil and gas industry, from both historical and forward looking perspectives.

SUMMARY OF MAJOR CONCLUSIONS

The Historical Record

- ***By all measures and interpretations the oil and gas upstream industry has been unprofitable since the mid-1980's.*** These conclusions are based on conventional measures of profitability which we believe are reasonable, and can be used and relied upon to judge the adequacy of profitability. It can be demonstrated that project returns are inextricably linked with financial accounting returns, and that financial accounting returns are linked with capital market returns and values. Further, there is a reinforcing linkage between capital markets and investment available for new projects.
- The Canadian upstream oil and gas industry has been unprofitable based on a number of key benchmark comparisons.

  (i) ***Returns generated are far below the industry's own historical cost of capital.*** Return on equity and capital employed has been inadequate for the upstream oil and gas industry, falling significantly below the industry's cost of capital since 1980.

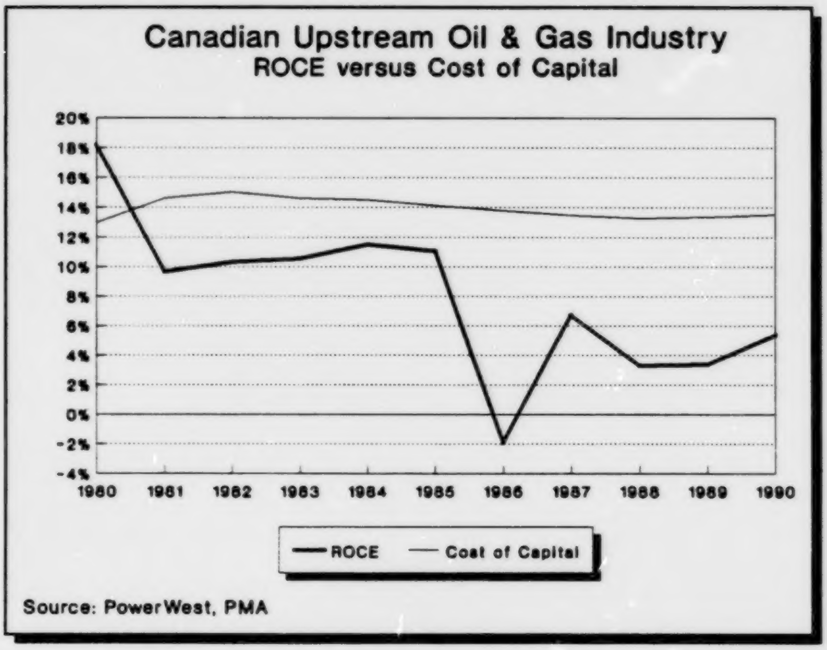
  - During the 1980's, industry average returns on equity and capital were 8.5% and 8% versus investment weighted costs of equity and capital of 18% and 14% respectively.
  - Post 1985, the deterioration in profitability has been particularly severe. Industry average returns on equity and capital were 2.5% and 3.3%, respectively.

  Upstream industry profitability has been severely depressed since 1985

  (ii) ***Industry returns are inadequate relative to other sectors of the Canadian economy.*** Although the oil and gas industry is unique, these comparisons are relevant and critically important as the upstream industry needs to compete with other industries in the Canadian economy for capital.

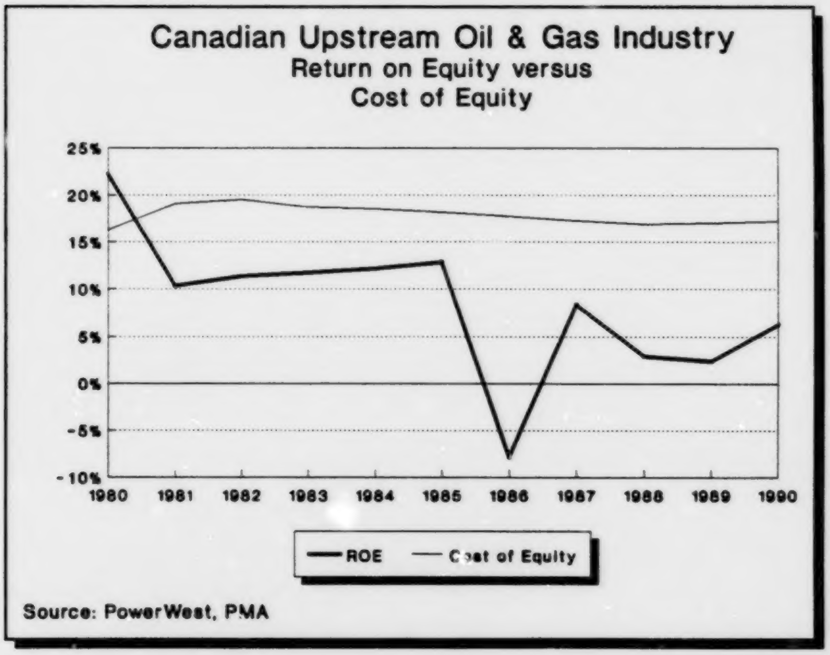
  - Since 1986, returns on equity and capital in all the other non-financial industries of the Canadian economy averaged 11% and 8%, respectively.
  - Over the same period, returns on equity and capital in the utility sector averaged 13% and 9%, respectively. The fact that returns for the upstream industry are significantly lower than the utilities is particularly disturbing as they represent the lowest risk and consequently have the lowest return requirement of all industries.

Industry returns on capital employed have been well below the cost of capital since 1981


Canadian Upstream Oil & Gas Industry
ROCE versus Cost of Capital

Source: PowerWest, PMA

Industry returns on equity have also been well below the cost of equity since 1981

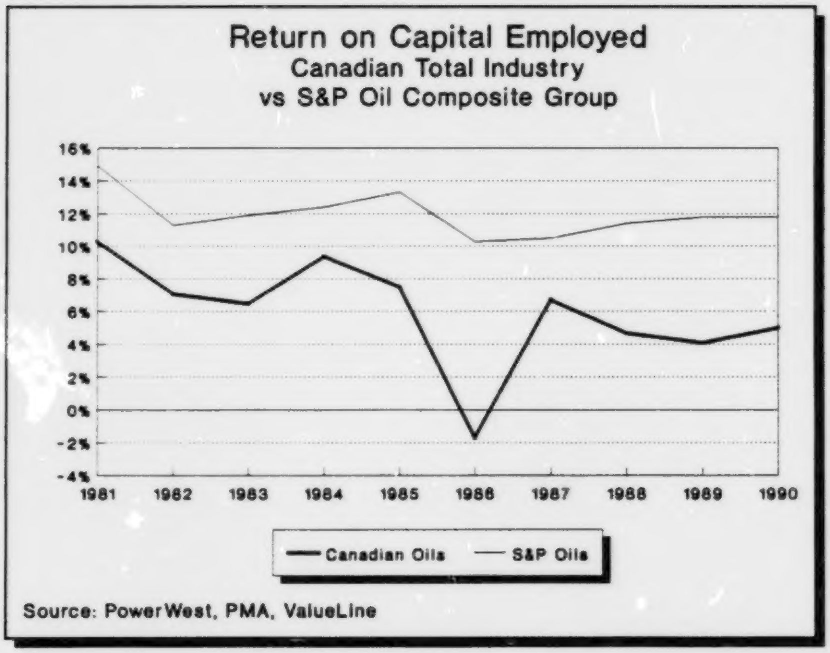

Canadian Upstream Oil & Gas Industry
Return on Equity versus
Cost of Equity

Source: PowerWest, PMA

(iii) ***Industry returns in Canada do not compare well to international oil and gas returns.*** This is a critical perspective in today's increasingly globalized economy. The Canadian industry also needs to compete with international oil companies for capital. Moreover, an increasingly larger portion of the cash generated internally by Canadian operations will flow to international areas if the returns in Canada remain unsatisfactory.

- Returns on equity and capital for the 16 companies comprising the S&P Oil and Gas Composite Index averaged 13.2% and 12.3% respectively over the past decade. These companies essentially achieved their average cost of capital.
- In contrast, the Canadian industry (total operations including the downstream) achieved returns on equity and capital of 5.7% and 6% respectively over the same period, well below their average cost of capital.

Industry returns are consistently below international oil and gas returns


Return on Capital Employed
Canadian Total Industry
vs S&P Oil Composite Group

Source: PowerWest, PMA, ValueLine

Behind the Poor Profitability

- ***Overly optimistic price forecasts and the healthy cash flows being generated by the industry in the early 1980's led to massive and, in hindsight, inappropriately high levels of capital spending.*** The actual course of prices relative to expectations is a major factor explaining low levels of profitability.
- ***The poor returns on this capital, though, were both "financial" and "physical".*** Poor physical returns are largely reflective of the limitations of the Western Canadian Sedimentary Basin (WCSB).

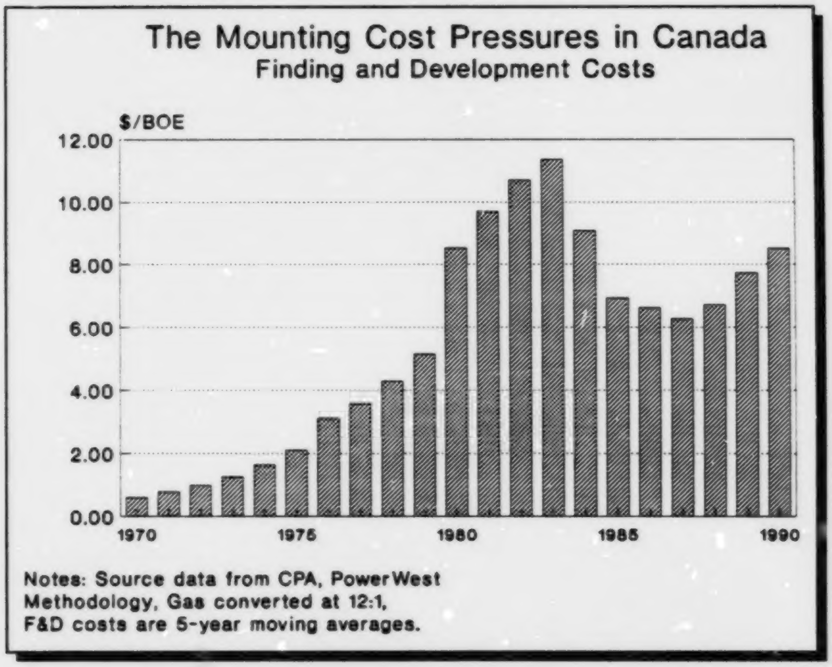
- The returns to drilling have declined dramatically since the late 1960's and early 1970's. The industry on average was finding 650 MB per successful oil well over the 1965-1970 period. In 1990, the five year average had fallen to less than 100 MB per successful oil well. Similarly for natural gas, finding rates were 9 Bcf per successful well over the 1965-70 period but have declined to about 1.3 Bcf in 1990.

Diminishing "physical" returns to drilling is a significant contributor to higher F&D costs

- Industry average finding and development costs increased nearly ten-fold over the 1970's due to the pursuit of high risk plays, rising drilling costs and, importantly, the declining prospectivity of the WCSB. F&D costs improved considerably in the mid-1980's but, disturbingly, now appear to be on the rise again, having moved up over the last few years to just over the $8/BOE level based on the latest 5-year average which includes 1990 results. To put these costs into perspective, U.S. F&D costs (calculated using the same methodology and comparable data) over the past five years have averaged $US 5.47/BOE, or $Cdn 6.83/BOE based on the average exchange rate over this period.

- Despite total capital investment of $56 billion between 1980 and 1990 (excluding frontier and oil sands), the Canadian conventional reserve base shrank by 10% on a BOE basis and production levels are up only 200 MBOE/d over this period.

F&D costs have resumed an upward trend since 1987



The Mounting Cost Pressures in Canada
Finding and Development Costs

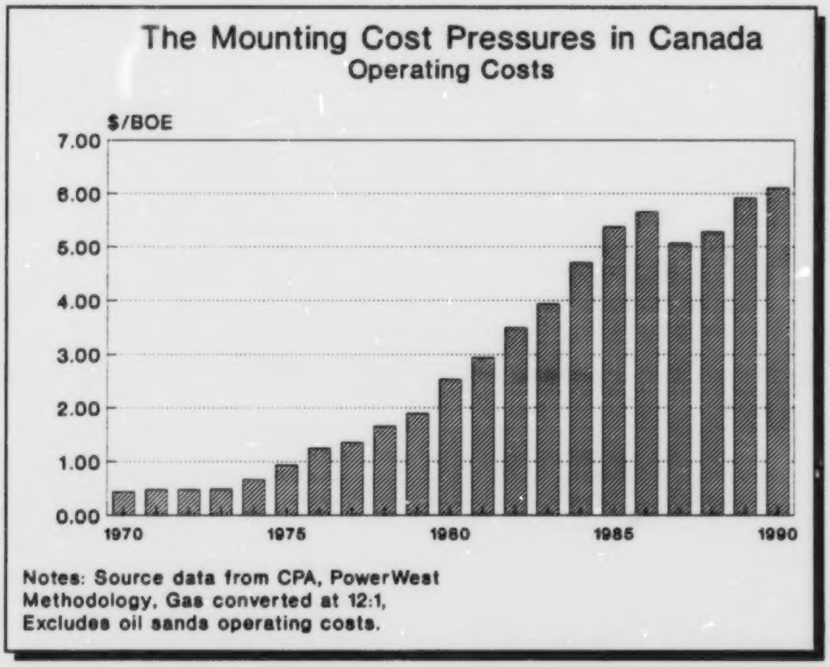
Notes: Source data from CPA, PowerWest Methodology, Gas converted at 12:1, F&D costs are 5-year moving averages.

- ***High operating costs are a major contributor to the poor profitability of the upstream industry, and are also reflective of the high cost nature of the WCSB.*** Operating costs have been in a seemingly inexorable upward trend since the early 1970's because of the general aging in the WCSB's largest fields and lower productivity, higher cost additions.

- Between 1975 and 1985, conventional operating costs grew at an annual average rate of greater than 20%, from just under $1.00/BOE to $5.37/BOE.

High operating costs are a major contributor to poor profitability and have resumed an upward trend since 1987

- Although the industry had some success controlling operating costs after the 1986 oil price crash, the upward trend has proven to be very difficult to control. Costs have risen by an average of 5% per year over the past four years, to an all time high of $6.10/BOE in 1990.
- These estimates exclude the very significant costs of Alberta's oil sands projects, current running at just over $12/B. If they are included, average operating costs in 1990 would be $6.90/BOE. In comparison average U.S. operating costs (calculated using the same approach) were just over $US 5.00/BOE in 1989, or about $Cdn 5.90/BOE.


The Mounting Cost Pressures in Canada
Operating Costs

Notes: Source data from CPA, PowerWest Methodology, Gas converted at 12:1, Excludes oil sands operating costs.

Royalty payments represent a significant withdrawal of funds from an unprofitable industry

- *A further major contributing factor behind the poor profitability of the upstream sector, other than prices and high F&D and operating costs, is the royalty burden provincial governments have placed on the industry.* Although royalties have fallen considerably in recent years, the fact is that they still represent a substantial withdrawal of funds from an industry that is not profitable, and are calculated based on revenues rather than the underlying profitability of the operations being taxed. Royalties paid by the industry have averaged $3.3 billion per year since 1986, a period when the industry's average ROCE was less than 3%.
- *The high cost of capital in Canada, specifically high interest rates, has also negatively impacted the upstream industry's profitability.* Rising inflation

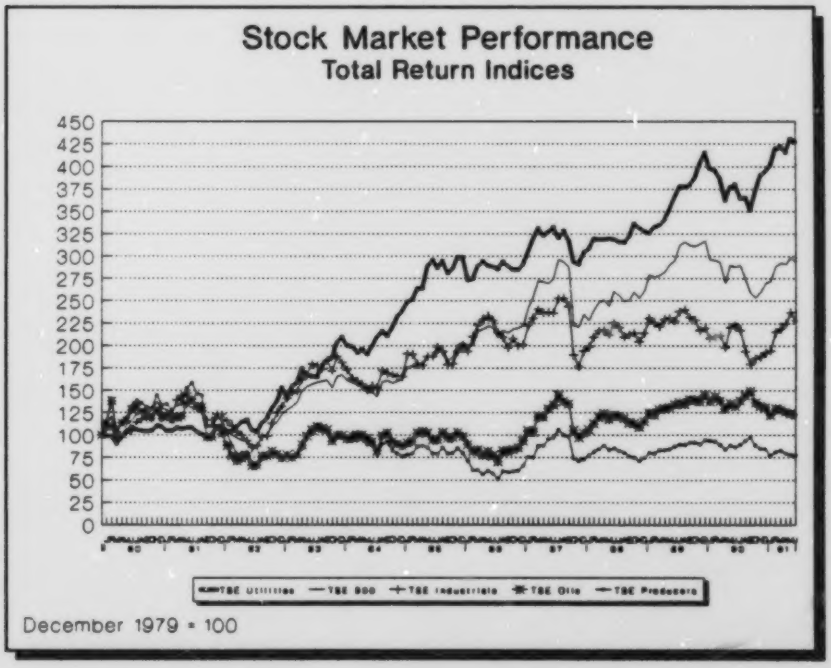
through the 1970's and early 1980's, combined with record government spending, have led to dramatic increases in interest rates and the cost of all sources of capital during the 1980's. More recently, the Bank of Canada's high interest rate policy since 1987 has also negatively impacted the industry by raising the cost of debt and, more importantly, by creating upward pressure on the Canadian dollar. We estimate that the appreciation of the Canadian dollar since 1985 has cost the producing industry a total of about $3.5 billion in lost revenue.

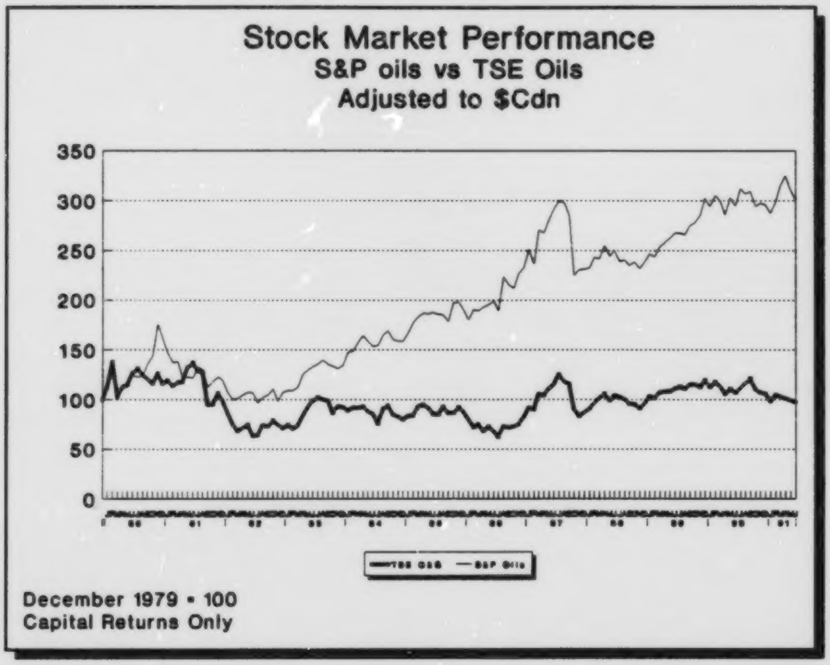
The Impact of Poor Profitability

- The consequences of low levels of profitability are wide ranging, and have had a severe negative impact on all stakeholders in the industry.

  (i) ***The owners of the industry, the equity holders, have suffered from inadequate returns.*** Canadian oil and gas equities, as measured by the TSE oil and gas index, are essentially flat over the past decade. In contrast, the industrials doubled over the same time frame, the TSE 300 index, reflecting the broad economy, tripled, and the utilities, which are the lowest risk corporate sector, quadrupled. Further evidence of the impact of poor profitability is that the combined equity of the 16 major U.S. companies comprising the S&P Oil and Gas Composite Index has tripled since 1980 despite facing the same price pressures for oil and gas as Canadian producers. This poor performance is both a consequence and confirmation of the poor returns in the upstream Canadian industry relative to other sectors in the economy and international energy companies.

The oils have significantly underperformed other sectors of the Canadian economy through the 1980's





December 1979 = 100
Capital Returns Only

International oil and gas companies have generated much better returns for shareholders than the Canadian oil and gas companies

(ii) ***The drop in capital expenditures post-1986 has had a severe impact on those areas of the oil and gas industry which provide services to the upstream sector.*** The groups that have been most severely hurt by lower levels of investment are the oilfield service, supply and equipment manufacturing industry (the service industry), the drilling industry, and geophysical firms. These groups are reliant on the activity of the oil & gas exploration and production companies as their sole source of revenue and consequently are seriously financially distressed.

Reduced investment and lower employment are natural consequences of poor profitability

(iii) ***The upstream industry's capability to provide highly paid and technically demanding employment opportunities is diminishing, as is its ability to sustain, let alone create, employment in other sectors of the economy.***

- We estimate that the major Canadian oil and gas companies have eliminated approximately 8,000 to 9,000 jobs since 1989. While junior and intermediate companies have absorbed some of the more skilled individuals, and some have departed to work internationally, we believe on the whole that there has been a net loss of employment in the sector.

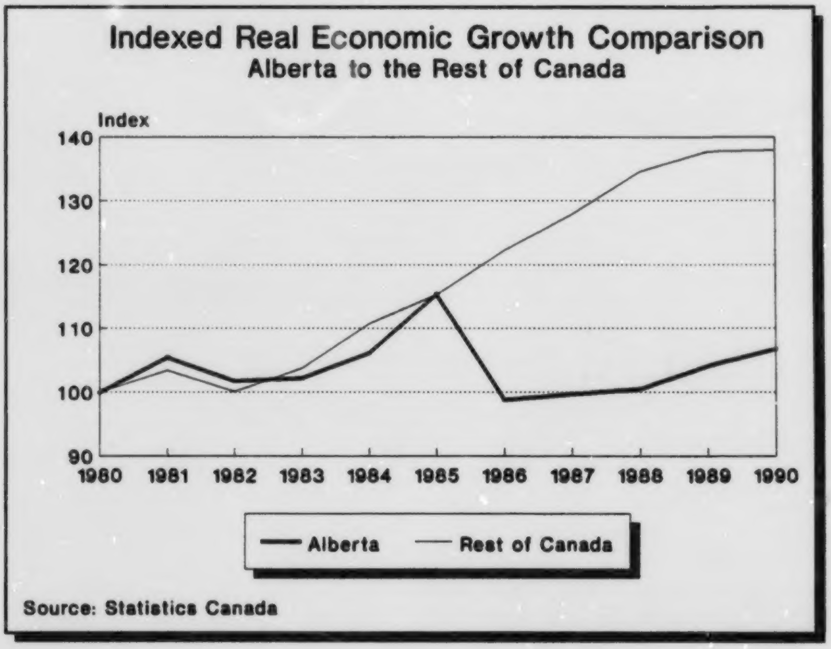
- There has been tremendous job loss in the drilling sector where the workforce has contracted by 50% since 1985, to less than 7,000 employees in 1990.

- In our view, the current round of staff reductions is particularly telling because it represents a fundamental change in the corporate structure of the industry and as yet shows no signs of abating. One important consequence of this general downsizing in the organizational resources of the upstream sector is the reduction in employment opportunities for new entrants into the workforce. Many companies have implemented hiring freezes and several have terminated on-campus recruiting.

The reduced contribution of the upstream sector post-1986 has led the Alberta economy to significantly underperform the rest of Canada

(iv) ***The contribution of the upstream sector to Alberta's economy has declined significantly since 1980, concurrent with the deterioration in the sector's profitability. This reduced contribution has had a substantial impact on the province's economy.***

- Alberta's economy significantly underperformed the Canadian economy between 1985 and 1990. Through the decade of the 1980's the Alberta economy expanded by less than 10% in real terms. In sharp contrast, the rest of the Canadian economy grew by nearly 40%.



Source: Statistics Canada

- The provincial government's revenue sources have been essentially flat since 1986. However, over this same period government spending has risen by about 5% per year. The result has been a persistent annual deficit that has averaged $2 billion per year since 1987.

Industry Outlook and Future Perspectives

- There is an understandable growing pessimism in both the producing and investment communities about the medium to longer-term outlook for oil and gas prices. For the past five years, recovery in prices has become a moving target continuously shifting further into the future. This is particularly true for natural gas. This year's plunge in gas prices has led to a dramatic reduction in price expectations relative to those that were widely held at the beginning of the year. Given the tremendous uncertainty with respect to future prices we have examined the outlook for the Canadian upstream sector under two different price tracks which bracket the low and high range in current industry views.

- ***Our projections indicate that the upstream sector is extremely vulnerable to a scenario of relatively flat prices due to high and increasing operating costs and depletion charges, and the significant royalty payments that still burden the industry.***

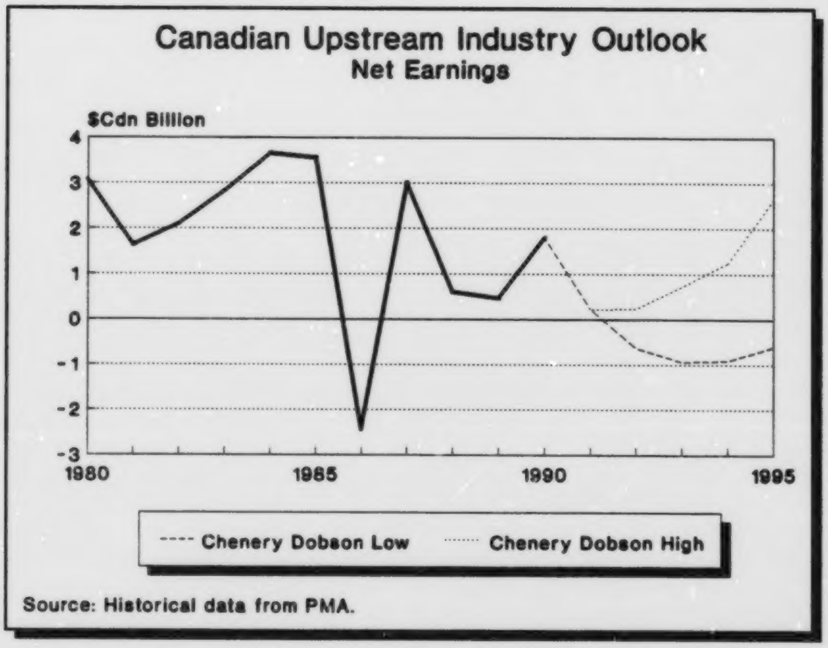
The upstream industry is expected to incur earnings losses through to 1995 under low price scenario

  - This vulnerability was clearly demonstrated in 1986 and 1988 and will be apparent again in 1991. Based on prices and corporate results through the first half of the year, our projections indicate that the internally generated cash flow in the upstream sector should fall by 25% this year, to about $6.1 billion.
  - The prospects for cash flow under the low price scenario are extremely poor. Higher interest expenses, continued growth in operating costs, production declines and lower gas prices combine to drag projected cash flows over the 1992 to 1994 period down to about the $5 billion per year level, below 1986's depressed level of $5.5 billion. Higher prices lead to some improvement in cash flows in 1995, but the projected level is still less than the expected cash flow for 1991, which by all accounts is being viewed as a very poor year.
  - ***Upstream earnings are even more leveraged than cash flows to changes in oil and gas prices because of the high and fixed nature of D&D charges (barring writedowns in the value of the assets being depleted).*** Net earnings in 1991 are projected to fall to a nominal $200 million, from $1.8 billion in 1990. Under the flat price scenario, net losses are projected over the entire 1992-1995 period.

We see very little scope for the industry to generate acceptable levels of profitability over the first half of the 1990's

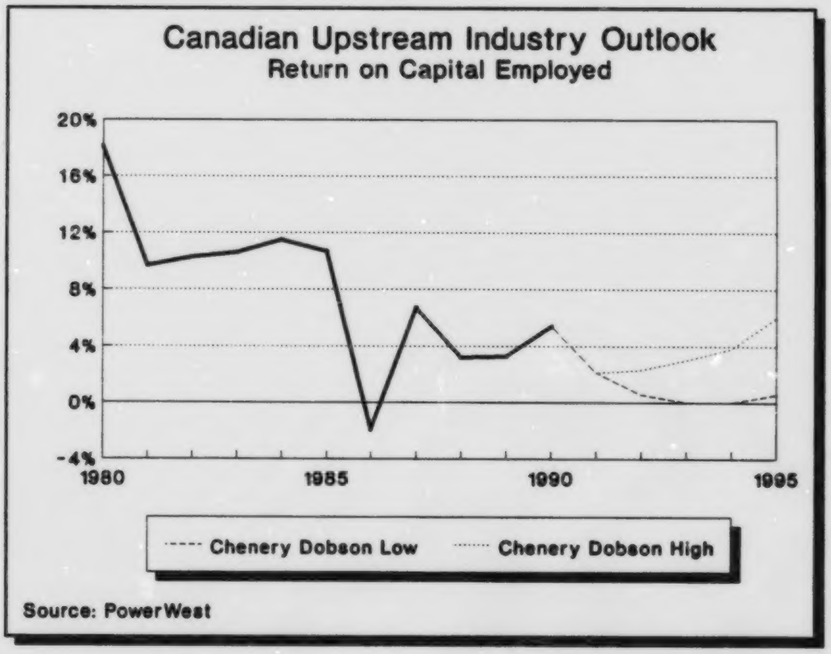
- ***We see very little scope for industry profitability to return to acceptable levels over the first half of the 1990's.***
  - In the low price scenario, the Canadian upstream sector would incur earnings losses and essentially negligible returns on capital over the entire forecast horizon. This again reinforces just how vulnerable the Canadian upstream industry is to a future where there is only minimal growth in oil and gas prices.
  - Even under an aggressive high price scenario, returns on capital remain below 6% through 1995, well below the industry's historical cost of capital.

The industry as a whole is expected to sustain significant losses if there is no price recovery



Source: Historical data from PMA.

Returns on capital do not approach acceptable levels even under an aggressive high price scenario



Source: PowerWest

- We have examined the industry outlook under a wide array of alternative scenarios to establish a better understanding of the conditions that might restore acceptable levels of profitability over the next five years.

- We find that the level of prices required to generate acceptable profitability over the next five years are well beyond even the most aggressive forecasts.

Prices required to generate acceptable profitability over next five years are well beyond reasonable expectations

- Even if the industry is able to hold operating costs constant over the forecast horizon, returns still remain well below acceptable levels through the forecast horizon under both scenarios.

- *The only scenario we can develop that restores acceptable levels of profitability in the sector by 1995 occurs under an aggressive, and probably unrealistically, high price forecast, combined with extreme cost cutting measures and a dramatic pull back of capital spending.*

- These scenarios all assume no change to the existing fiscal regime. Under all scenarios, reduced royalties have the potential to make a significant contribution to improved profitability.

Extreme cost cutting measures and reduced capital outlays are necessary but not sufficient to restore acceptable levels of profitability

SENSITIVITY ANALYSIS SUMMARY

	1992	1993	1994	1995
Base Cases				
Low Prices				
ROCE's	0.6%	0.0%	0.0%	0.6%
ROE's	-2.1%	-3.3%	-3.4%	-2.3%
High Prices				
ROCE's	2.3%	3.0%	3.8%	6.0%
ROE's	0.8%	2.4%	4.2%	8.7%
Sensitivity Cases	$US/B WTI			
What level of oil prices are required to generate 12% ROCE's if gas prices were at $2/Mcf?	36.0	37.5	41.0	42.5
What level of oil prices are required to generate 12% ROCE's if gas prices were at $3/Mcf?	31.5	33.5	36.0	38.5
High Price Cases Only:				
What if operating costs were constant?(1)				
ROCE's	3.0%	4.2%	5.3%	7.8%
ROE's	2.3%	4.8%	7.4%	12.3%
What if reinvestment was 50% of cash?				
ROCE's	3.0%	3.8%	4.8%	7.5%
ROE's	2.3%	4.7%	7.0%	11.6%
What if operating costs were constant and reinvestment was 50% of cash?				
ROCE's	3.7%	5.0%	6.4%	9.5%
ROE's	3.7%	6.8%	9.7%	14.5%

Notes: 1. Capital spending maintained as per high price scenario.

The increasing costs of complying with ever tightening environmental standards will negatively impact industry profitability

- *The growing concern over the environment has extremely important but unfortunately negative implications for the profitability of the upstream Canadian industry.* At this point in time it is very difficult to quantify the impact of the policy initiatives now being considered and we have therefore not explicitly included them in our analysis. However, the general trend is clear. Tighter environmental standards will lead to higher costs, both capital and operating, and increased delays, complexities and costs associated with more regulation. These burdens will magnify the mounting cost pressures that the industry already faces, and prospects are very poor that the industry will be able to earn a return on these expenditures. Canadian oil and gas producers are price takers for both oil and gas and the higher costs of complying with stricter environmental standards will be very difficult to pass through to consumers unless they are equally borne by U.S. and international competitors.

The outlook for upstream investment and drilling activity is poor under the current fiscal regime

- *Our analysis points to the conclusion that the general outlook for investment and drilling activity in the oil and gas sector is poor under the current fiscal regime.*

  - We feel it will be very difficult for the industry as a whole to generate acceptable rates of return on future conventional oil exploration, even under the high price scenario. For natural gas, investment economics are extremely poor under the low price scenario based on full cycle economics and average finding and development costs over the past five years. The relatively poor investment economics for both oil and gas will constrain future capital spending.

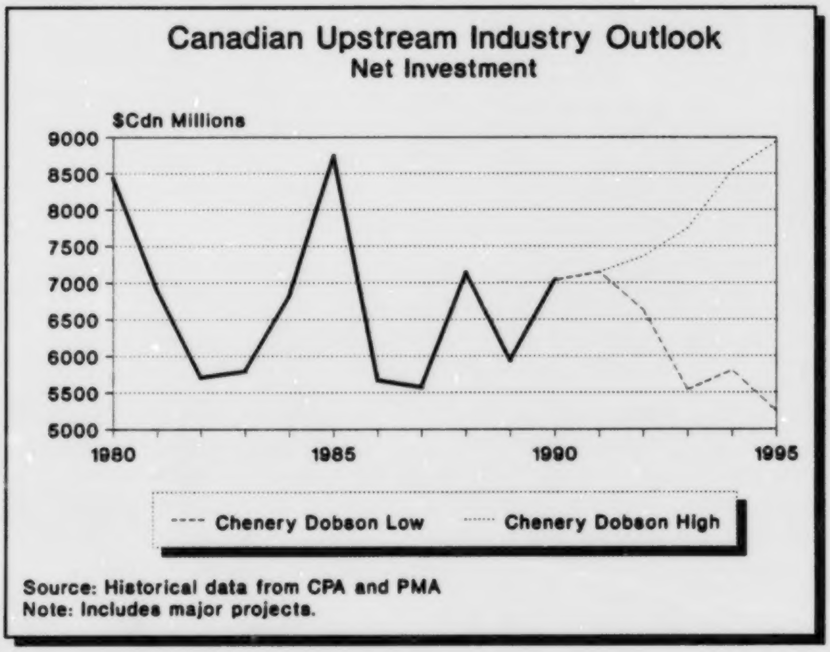
  - The outlook for capital spending under the low price scenario is very bleak. After Caroline and the Husky upgrader are completed in 1992, there are no major projects on the books with the exception of Hibernia. Based on an expected approximate 80% reinvestment of cash flow, investment in the conventional areas would fall to an average of $4.5 billion over the 1992 to 1995 period. To put this into perspective, investment in the conventional areas averaged $5.9 billion per year over the 1980-85 period, and $5.5 billion per year over the 1986-90 period.

  - It should be emphasized that these projected depressed levels of capital investment embody very low levels of discretionary, new project investment. The industry has maintenance capital requirements that run at an estimated $2-$3 billion per year. This capital is required to maintain the efficient operation of older fields, meet contractual obligations for natural gas, comply with existing environmental guidelines and to do the drilling necessary to avoid relinquishing lease positions. Under our low price scenario, we estimate that discretionary spending would be a relatively low $1.5 to $2.5 billion per year. This could potentially be the lowest level of discretionary capital spending in the upstream sector of Canada since the mid-1970's.

  - As an important qualification to the above, the industry will always have some profitable new projects to pursue, resulting more than anything from past exploration successes. This should maintain a certain base level of discretionary spending. It is also important to recognize that while the sector as a whole is likely to show little growth and may even contract over the first half of the 1990's, certain companies will continue to grow strongly. There are several intermediate and senior companies with excellent F&D records, and a burgeoning group of well managed junior companies, which have the potential to be relatively profitable in the current price environment.

- ***Based on projected levels of capital investment, drilling activity would be severely depressed under the low price scenario, and would increase only modestly under the high price scenario.*** As the financial condition of the service sector is acutely depressed at current activity levels, this implies continued financial distress and contraction for the service sector.

Industry investment would be severely depressed under a low price scenario



Source: Historical data from CPA and PMA
Note: Includes major projects.

Industry investment is inadequate to maintain the reserve base even under a high price scenario

- The combination of relatively low drilling activity and the poor "physical" returns to drilling that are now characteristic in the WCSB are expected to lead to further contraction in the conventional oil and natural gas reserves throughout the forecast horizon under both scenarios. To put this into perspective, at current F&D costs of roughly $8.50/BOE, the industry would have to spend $8.5 billion per year to maintain the conventional reserve base. Since 1986, conventional spending has averaged $5.5 billion per year and just reaches the $8.5 billion per year level by 1995 under our high price scenario.

KEY IMPLICATIONS

- ***A key conclusion and implication relates to the importance of profitability. The issue of profitability must be a central consideration by all of those who have a vested interest in the oil and gas sector.*** Absolute levels of revenues and cash flow, producer netbacks and other similar measures tell only a small part of the story. All players must be focusing on both ***income*** and ***capital*** to

Profitability is important and the consequences of persistent poor profitability are powerful

understand the key financial fundamentals of the industry. The consequences of sustained poor profitability are powerful. At the most elemental level, an industry that is not profitable will inevitably be forced to contract.

- Internally generated cash flow is redirected to other sectors of the economy, or other countries, that offer better prospective returns, or returned to the owners of the industry.
- Capital becomes more difficult and increasingly expensive to raise.
- Capital investment is reduced and employment is diminished.

- ***The fact that industry cannot restore acceptable levels of profitability over the first half of the 1990's under aggressive market recovery assumptions is a disturbing conclusion.*** It may be argued that commodity fundamentals are not being understood and that there may be a major up-cycle in prices, more extreme than the high price scenario used in this analysis. This would in effect "bail out" the industry. However remote this may seem, it is a possibility, but the industry of course cannot plan on this type of speculative, if not wishful thinking. Historical experience has dramatically illustrated the risks of depending on price recovery. ***To remain sound and viable, the industry must be capable of operating profitably in a modest price environment.***

The limitations of the WCSB pose a major challenge to restoring profitability in the upstream industry

- ***There appears to be no easy way to restore acceptable levels of profitability as a large part of the problem relates to the limitations of the WCSB.*** It is not reasonable to think that upward cost pressures can be reversed. High and rising operating and overhead costs can be mitigated through corporate rationalization and restructuring efforts and technological advances, but the aging of the existing major oil and gas pools will continue to put upward pressure on costs. The costs of finding and developing new reserves are currently high and, similar to operating costs, appear to be increasing for reasons relating to the nature and maturity of the WCSB. It is a sobering conclusion that it is only through extreme cost cutting and an unparalleled pull-back in reinvestment levels that the industry might be able to restore acceptable levels of profitability, particularly given that this only occurs in a price scenario which most senior decision makers in industry would view as highly optimistic. We would also emphasize that these considerations ignore the upward pressure that looming environmental initiatives will exert on the industry's cost structure. These additional costs will be a further drag on industry profitability.

- The industry cannot control prices but to an extent it can control its costs and certainly its levels of capital spending. Cost reductions and reduced and redirected capital spending form the basis of the industry's rationalization and restructuring plans. If prices remain low, we would expect to see a severe contraction in capital spending over the next five years, particularly after the major Caroline and Hibernia projects are completed. Rationalization, restructuring and consolidation within the industry would continue and the capacity of the sector to provide new employment opportunities would continue to diminish. The spillover effect of this contraction on other sectors of the economy, notably the service and construction sectors, would also be very significant. While a detailed analysis of the implications these trends hold for the Alberta economy is beyond the scope of this report, we believe they raise some extremely important and sobering questions, in particular, with regards to the longer-term economic growth prospects of Alberta.

The consequences of poor profitability – reduced capital spending and a diminished capability to provide employment – have very significant and negative implications for the future of the Alberta economy

- *A key conclusion of this report is that the existing royalty regime is inappropriate given current business and financial realities.* It is hard to see how the concept of "economic rent" can apply to an industry that has been unprofitable for many years, and where there is little basis to expect a restoration of reasonable profitability into the foreseeable future. The royalty structure today does not fit the circumstances of an unprofitable industry. Nor does it reflect the realities of today's investment economics which are very marginal under current consensus price forecasts. The result is to force more industry downsizing than would otherwise be the case--which means less capital investment and less employment.

- *A broad implication of this study is the importance of co-operation and mutual support on the part of all stakeholders in the industry to improve profitability.* Industry is pursuing broad cost reduction and productivity enhancement strategies. Governments must also examine steps that they can take to create a more supportive business environment. A constructive and open process to examine the alternatives is in the best interest of all stakeholders. The appropriate steps to be taken must ultimately recognize certain current realities of the upstream Canadian oil and gas industry, as follows:

  - Canada is a high cost producer of oil and gas and extremely vulnerable to a scenario in which there is minimal price growth from current levels.

  - Cost pressures in the Canadian upstream industry are growing. Finding and development costs and operating costs have trended up over recent years. Environmental related costs will exacerbate this problem.

  - The industry is not profitable now and the prospects for a return to profitability over the next five years are fairly remote.

  - Investment economics for both oil and gas in the current fiscal regime are, on average, extremely marginal under a scenario of relatively flat prices.

All stakeholders in the upstream industry, including governments, must focus on improving profitability and creating a business environment that reflects the "realities" of the Canadian oil and gas industry

SECTION I HISTORICAL PROFITABILITY OF THE CANADIAN OIL AND GAS INDUSTRY

MAJOR CONCLUSIONS

1. The Canadian upstream oil and gas industry has invested approximately $120 billion in exploration and development activities since the discovery of Leduc in 1947. Most of that capital, approximately 75%, has been invested since the dramatic escalation in international energy prices in the late 1970's. The total capital employed in the upstream industry was approximately $20 billion at the end of 1979 and has since increased to $54 billion as at year-end 1990. Although $55 billion of oil and gas acquisitions were completed in the industry over the past 15 years, we estimate that acquisition premiums represented less than $4 billion of the industry's total capital at the end of 1990. The industry over this same time period discovered approximately 33.7 billion BOEs of oil and gas reserves, comprised of 19 billion barrels of oil and liquids, 2.6 billion barrels of nonconventional oil reserves, 145.3 Tcf of natural gas and 184 million tonnes of sulphur. *To the end of 1978, the industry had discovered 23.7 billion BOEs of reserves, or 70% of total reserves discovered to date in Canada for 25% of the total capital (43% of the total on a real dollar basis) invested to date on exploration and development. Since 1978, a further 10 billion BOEs of reserves have been added but at a substantially higher cost.*

2. Income for the upstream industry averaged less than $500 million annually prior to 1974 and increased dramatically in the new OPEC era, from $650 million in 1973 to $3 billion in 1980. The five-fold increase in net income was accompanied by only a three-fold increase in capital employed. The adverse consequences of burdensome fiscal regimes, increasing costs, and then deregulation of markets in a weak energy market in the mid 1980's resulted in a reversal of industry fortunes. *Net income which had averaged $2 billion annually between 1974 and 1980, fell to an average of $1.6 billion between 1981 to 1990 while total invested capital more than doubled through the decade.*

3. *Increasing inflation through the 1970's and into the early 1980's, combined with record government spending, resulted in a dramatic increase in interest rates and the cost of all sources of capital.* Canadian T-bills, essentially the risk free rate, which had averaged 4.5% in the 1960's and early 1970's rose steadily with the dawn of the OPEC era and through the 1970's, to an all time annual peak of 17.8% in 1981. These rates set a much higher base for returns in capital markets. *The costs of capital to the Canadian oil and gas industry increased from an average of approximately 9.8% in the 1970's to 13.9% in the 1980's and at this time we estimate the investment weighted cost of capital to the industry at 13.5%. Costs of equity capital increased from 12.1% in the 1970's to 18% in the 1980's.*

4. *There are many concepts and measures of profitability in financial theory and as adopted by industry. A key conclusion of this study is that conventional accounting measures of profitability are reasonable, and can be used and relied upon to judge the adequacy of profitability.* It can be demonstrated that project returns are inextricably linked with financial accounting returns, and that financial accounting returns are linked with capital market returns and values. Further, there is a reinforcing linkage between capital markets and investment available for new projects.

5. The profitability of the upstream oil and gas industry, as measured by return on equity and return on capital, has been rigorously and comprehensively analyzed and compared against three important benchmarks; 1) the industry's costs of equity and total capital; 2) returns earned by other industries in the Canadian economy; and 3) returns earned by the international oil and gas industry. The primary focus of this review is over the past decade as this is a period of most relevance and data is readily

available and reliable. We have, however, made longer-term calculations based on our own estimates of industry capital and income prior to 1980.

6. ***Return on equity and capital employed has been inadequate for the upstream oil and gas industry, falling significantly below the industry's cost of capital since 1981. During the 1980's the industry's average returns on equity and capital were 8.5% and 8% versus investment weighted costs of equity and capital of 18% and 14% respectively. The deterioration in profitability has been most severe post the oil price collapse in early 1986. Returns on equity and capital have averaged 2.5% and 3.3%, respectively, since 1986.***

7. The capital employed by the upstream industry has been influenced by factors other than capital raised or retained for direct investment in exploration and development. Acquisitions totalling $55 billion have impacted the capital base of the industry over the past 15 years as have approximately $9 billion of writedowns. We estimate that acquisition premiums of approximately $15 billion as a result of these corporate transactions have been added to total upstream invested capital over that time period. Restating capital and income over the decade to reflect these premiums raises ROCE's by approximately 3% higher over the first half of the decade, resulting in proforma rates of returns that are near the industry's cost of capital. Importantly, as acquisition premiums have been largely depleted or written off, the net impact of these charges do not significantly affect our conclusions on industry profitability over the second half of the decade.

8. ***The upstream oil and gas industry fell short of overall levels of industry profitability in the Canadian economy during the 1980's. Although the oil and gas industry is unique, these comparisons are relevant and important as the upstream industry needs to compete with other industries in the Canadian economy for capital.*** Average returns on equity and capital for all non-financial industries (excluding oil and gas) were 10.2% and 7.8%, versus 7.1% and 7% for the upstream sector respectively (from 1981 to 1990). In the second half of the decade the returns for all non-financial industries were 10.8% and 8.3% (equity and capital respectively) versus 2.5% and 3.3% for the oil and gas industry. Average profitability for the upstream sector was 5.6% and 0.8% below that of utilities (for equity and capital respectively) during the past decade, a disturbing result for industry and investors given that utilities represent the lowest risk and consequently have the lowest return requirement of all industries in the economy.

9. ***The profitability of the Canadian oil and gas industry is substantially poorer than the U.S. based energy industry.*** Returns on equity and capital for the total Canadian industry (upstream and downstream) were compared with the 16 companies comprising the S&P Oil and Gas Composite Index over the 1980 to 1990 period. In contrast to the Canadian oil and gas industry, which achieved levels of profitability that were 9% and 6% short of its cost of equity and total capital respectively, the U.S. companies achieved returns commensurate with their costs of capital. The U.S. companies were able to achieve this profitability and growth on a capital base three to four times that of the Canadian companies and through the collapse of international oil prices in 1986. An important factor in explaining the difference between the Canadian and international companies is that finding and development costs and reserve replacement ratios are more favourable internationally.

10. ***The poor and deteriorating profitability of the Canadian oil and gas industry has been clearly reflected in capital markets. Canadian oil and gas equities over the decade are flat while the producers, which offer a better measure of the performance of the upstream companies, are down 25%. In contrast, the equity of industrial corporations doubled, the TSE 300 tripled and utilities quadrupled. In an international context, Canadian oil and gas equities were flat while the S&P Oil and Gas Corporate Index tripled over the past decade (adjusted for the Canadian dollar). The poor performance of oil and gas equities fairly reflects the poor fundamentals for the group over the past decade. In addition to the obvious consequence of disappointing returns to the owners of the industry, this performance also effectively increased the cost and difficulties of raising equity capital to finance growth for the Canadian upstream industry.***

SECTION I

HISTORICAL PROFITABILITY OF THE CANADIAN OIL AND GAS INDUSTRY

INTRODUCTION

This section provides a review of the historical record of profitability in the Canadian upstream oil and gas industry. The section commences with a discussion of the most appropriate measures by which to calculate profitability. We also identify and discuss some of the measures that are inappropriately used in reviewing or commenting on industry profitability. We then establish three critical benchmarks for assessing the adequacy of historical levels of profitability as follows: 1) historical cost of capital; 2) returns earned by other Canadian industries; and 3) returns earned by the international oil and gas industry. The actual level of profitability in the Canadian oil and gas industry is compared to each of these benchmarks and conclusions are drawn.

Appropriate Measures of Profitability

The most fundamental principle of capital markets and investment is that capital must earn a return and related to this is the corollary that the greater the risk the greater the required return. For example, if the rates on risk free debt instruments (such as government T-bills) are 10%, it is clear that for the industry to raise investment capital or to justify re-investing its own capital, it must offer investors returns in excess of risk free rates, with a premium commensurate with the risk in that industry. There are a number of conceptual and analytical models as well as empirical evidence in capital markets to determine the cost of capital. This issue will be dealt with later in this section.

A good starting point in defining the appropriate manner by which to measure industry profitability is to recognize on what basis and by what criteria was capital invested in the Canadian oil and gas industry. Excluding acquisitions, essentially all capital for the upstream sector was invested on a project or play basis in the exploration for and development of oil and gas reserves. Companies approved new oil and gas projects or ventures only where the "expected returns" or cash flow (on a net present value basis) exceeded the cost of the funds invested in those projects. Virtually all capital has been and continues to be invested on this basis. Integral to project evaluation is the discounting of cash flows over the life of the project at the investor's weighted average cost of capital. Only projects that exceed this threshold are pursued.

A fundamental principle of capital markets and investment is that capital must earn a return and the greater the risk the greater the required return

The discounted cash flow model of profitability is extremely difficult, if not impossible, to apply on an industry basis. We need a proxy for this measure that correlates closely with project returns and the calculation of the cost of capital. Moreover, this measure must be based on available data and apply to the relevant time periods being evaluated.

In our opinion, the financial accounting measures of return on equity and return on capital employed are appropriate measures of the actual project returns that are being generated over time. These measures can be readily calculated from available data on the Canadian oil and gas industry as a whole and can be compared to the industry's historical cost of capital, other Canadian industries, and many of the international oil and gas companies.

These measures are defined as follows:

- *Return on Equity (ROE)* is defined as net income for the period divided by shareholders' equity. Shareholders' equity is calculated on an average basis for the period. This measure calculates the return earned on the capital that shareholders have invested in the industry.

- *Return on Capital Employed (ROCE)* is defined as net income plus deferred taxes plus interest on an after tax basis, all divided by total capital employed which is comprised of debt, equity, and cumulative deferred taxes. Generally, the denominator is defined as total assets minus current liabilities and is calculated on an average basis for the period. This measure calculates the return to *all* capital invested in the corporation.

There are often concerns expressed as to whether financial accounting measures adequately reflect profitability and returns. Some of the concerns that are commonly expressed are discussed below:

Accounting measures of profitability adequately reflect the underlying returns being earned by investment capital

- Accounting measures understate the profitability of new projects and overstate it for older ones. This is particularly true in the oil and gas industry where reinvestment levels are generally much higher than in other industries. The constant stream of investment results in high depreciation charges which depress earnings and book measures of returns. This observation is largely true. However, the industry is a mix of old and new projects, and in a "steady state" situation in a mature industry, accounting returns converge on project returns. This conclusion is supported by an empirical proof provided in Appendix I.

- Book returns can be distorted by different accounting procedures, a problem that often arises in the oil and gas industry due to the two different accounting methodologies in use: (a) successful efforts, where only the capital costs associated with successful exploration and development are capitalized, dry holes and associated costs are expensed; and (b) full cost accounting, where all capital costs are capitalized (including a portion of interest charges and overhead expenses). Over the short-term, these two accounting approaches can lead to significantly different financial results in terms of earnings and cash flows. However, over the long-term, they will produce similar results.

Despite the apparent shortcomings, it is our judgement– supported by financial, industry and capital market analysis–that the book measures of ROCE and ROE over time adequately reflect the underlying returns being earned by invested capital. These measures can properly be compared to the cost of that capital, and used to assess the relative profitability of different sectors in the economy or different companies. Appendix I summarizes our analytical work substantiating this view.

Inappropriate Measures

It is worth noting other measures that are often referred to by industry observers in commenting on industry profitability that in themselves are not appropriate measures of profitability.

- *Margins* can be defined in many different ways but are generally intended to reflect the percentage of sales that contribute to profits. This is really a measurement of company efficiency. Although most high margin industries are generally profitable, without supporting measures, margins do not provide an accurate indication of profitability as they are only part of the numerator in the return equation and ignore the capital invested.

Inappropriate measures of profitability such as margins, netbacks and cash flows do not reflect the underlying capital base

- *Netbacks* are a widely used measure in the oil and gas industry and can be simply defined as the profit generated per unit of production sold, ie., the selling price of oil or gas less all of the associated costs. Very similar to margins, netbacks are more of an efficiency measure than an indicator of profitability as the capital component is ignored.
- *Cash Flow* is the lifeblood of the oil and gas industry. The magnitude of the cash flows that many of the large producing companies generate has created a public perception that the oil business is extremely lucrative. This is a complete misunderstanding as, similar to margins and netbacks, cash flow in isolation ignores the capital base that is generating it and also ignores the capital required to grow or at least sustain it. The reason that the oil and gas industry generates such tremendous levels of cash flow is because of the very substantial capital investments that have been made to find and develop oil and gas reserves. From 1978 to the present, the industry invested approximately 3 times the amount of capital than it did cumulatively in all the years prior to 1978.

Historical Profitability Compared to Industry Cost of Capital

The Canadian upstream oil and gas industry has invested approximately $120 billion in exploration and development expenditures over the past 40 years. Over this same time period the industry discovered 19 billion barrels of conventional oil and liquids, 2.6 billion barrels of nonconventional oil reserves, 145.3 Tcf of natural gas and 184 million tonnes of sulphur. Interestingly, and not surprisingly, most of the capital invested in the industry has occurred over the past 10-15 years, coinciding with the dramatic increases in international energy prices. To the end of 1978 the industry had invested $23.7 billion ($93.1 billion in real 1990 dollars) to add 23.7 billion BOEs of reserves. In the past 13 years the industry has invested $89.6 billion ($120.8 billion in real 1990 dollars) to add 10 billion BOEs of reserves.

Regulation, and then deregulation of energy markets, federal and provincial energy policies, and resource taxation have had a significant impact on industry revenue and income over this same time period. The Canadian upstream oil and gas industry is currently deregulated and receives international prices for hydrocarbons and related products adjusted only for transportation, quality, and exchange rates. Revenue taxes have been eliminated and the industry is currently burdened by resource royalties, mineral taxes, property taxes, and corporate income taxes. The next section of this report examines in detail the formation of capital in the industry and the influence of energy markets, regulation, fiscal regimes, industry costs and trends in the Canadian resource basin on the historical profitability of the Canadian oil and gas industry.

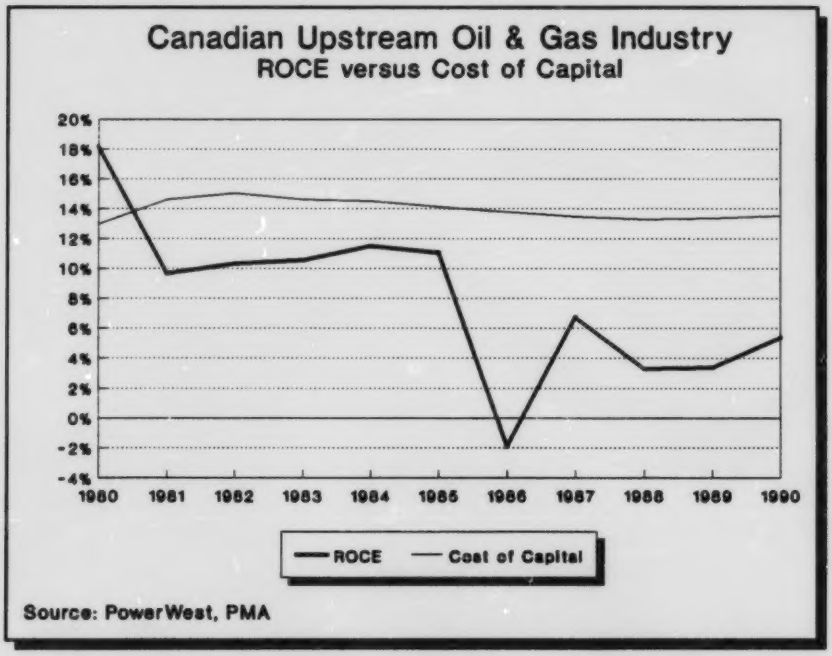
The following tables and graphs summarize the record of profitability for the Canadian upstream oil and gas industry focusing on returns to both equity and total capital and provide a comparison of those returns to the cost of that capital. The calculations are based on the accounting measures that were defined above. We note that the availability of data limits a rigorous assessment of this review to the 1979 to 1990 period. We have, though, made longer-term calculations based on our own internal estimates of industry capital and income prior to this period. Also, the fact that many Canadian companies active in the upstream have capital employed and generate income from other business areas, has required various adjustments to industry data to isolate returns that have been achieved solely from upstream oil and gas operations.

ROCE's

We have compared the actual returns of the industry for both equity and capital to the "investment weighted" cost of that capital. Cost of capital is first calculated on an annual basis reflecting current expectations for the cost of equity and debt. In recognition of the fact that returns on capital in the industry are a combination of the returns earned on capital that has been employed in the current as well as all previous years, the investment weighted cost of capital weights each previous year's cost of capital by the dollar value of investment in that year. Investment capital in the weighting formula is amortized over twenty years. This approach smooths the cost of capital over time, recognizes the longer-term nature of investments and return and appropriately matches returns with the capital employed to earn those returns. The table included in this section summarizes the components of total capital and income generated to these sources of capital over the past twenty years, compared to the industry's cost of capital and equity. A more detailed discussion and calculations are provided in Appendix II.

Figure I.1

Upstream returns on capital employed have deteriorated seriously since 1980



Source: PowerWest, PMA

Return on capital employed for the industry has been inadequate since 1980, falling significantly below the industry's cost of capital. In the second half of the 1970's, primarily as a result of the rapid increase in international and Canadian energy prices and the availability of low cost reserves, the industry achieved excellent rates of return in excess of the cost of capital which was approximately 9.5% over this period. In contrast, during the 1980's the average return on capital employed was 8.0% compared to an investment weighted cost of capital of approximately 14%.

Table I.1

CANADIAN UPSTREAM OIL AND GAS INDUSTRY
Return on Capital and Equity
($Cdn Billions)

Year	Total Capital	Equity	Income	Deferred Taxes	Interest AT	Income + Def Taxes + Interest AT	ROCE (%)	Cost of Capital (%)	ROE (%)	Cost of Equity (%)
1970	7,853	N/A	330	39	30	399	4.8	9.4	NA	NA
1971	8,395	N/A	365	48	28	441	4.8	9.0	NA	NA
1972	9,013	N/A	415	81	27	523	5.1	8.8	NA	NA
1973	9,573	N/A	652	157	30	839	7.3	8.8	NA	NA
1974	10,081	N/A	1,149	259	33	1,441	11.9	9.2	NA	NA
1975	10,815	N/A	1,476	256	41	1,773	14.8	9.5	NA	NA
1976	11,840	N/A	1,597	265	97	1,959	14.3	10.1	NA	NA
1977	13,699	N/A	2,096	357	82	2,535	18.4	10.3	NA	NA
1978	16,128	N/A	2,021	519	102	2,642	12.6	10.8	NA	NA
1979	20,331	11,237	2,434	761	275	3,470	19.6	11.8	21.7	14.9
1980	26,895	14,887	2,905	1,144	236	4,285	18.1	13.0	22.2	16.3
1981	34,448	16,839	1,646	808	521	2,975	9.7	14.6	10.4	19.1
1982	42,083	20,128	2,100	1,032	821	3,953	10.3	15.0	11.4	19.5
1983	42,204	22,400	2,505	1,202	748	4,455	10.6	14.6	11.8	18.7
1984	52,398	24,720	2,863	1,726	868	5,457	11.5	14.5	12.2	18.6
1985	56,680	26,499	3,292	1,723	825	6,038	10.7	14.1	12.9	18.2
1986	46,638	22,026	-1,892	32	895	-965	-1.9	13.8	-7.8	17.7
1987	49,320	25,316	1,995	372	861	3,228	6.7	13.5	8.4	17.3
1988	52,167	27,631	786	95	809	1,690	3.2	13.3	3.0	16.9
1989	55,211	27,552	659	442	733	1,810	3.3	13.4	2.4	17.0
1990	54,357	28,004	1,758	519	721	2,998	5.4	13.5	6.3	17.2
Averages										
1970-1990							9.6	12.0	N/A	N/A
1980-1990							8.0	13.9	9.1	17.9

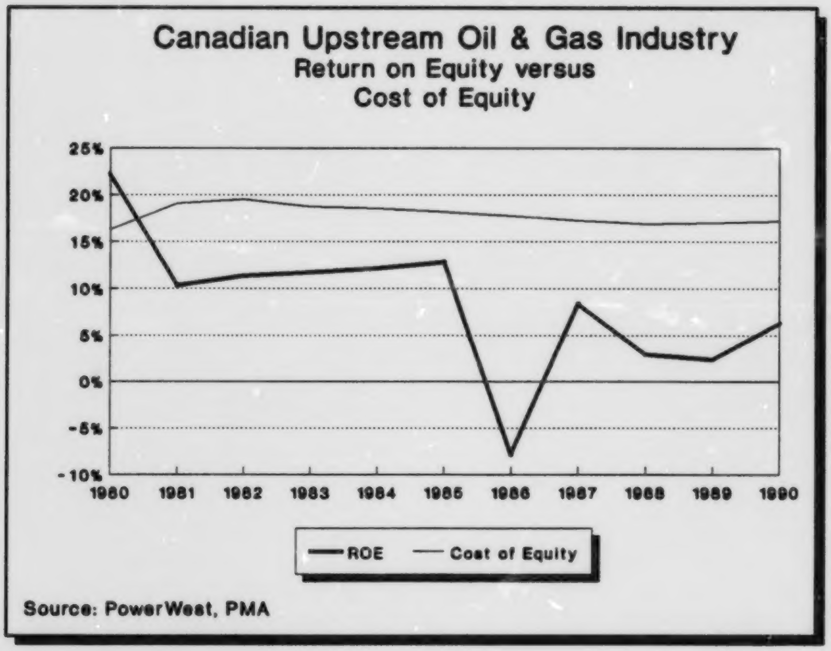
Notes:
1. Interest is stated on an after tax basis using statutory tax rates.
2. 1970 to 1978 data estimated by PowerWest based on CPA information.
3. 1979 to 1990 data sourced from the PMA.
4. Equity capital in the upstream was estimated based on the same debt/equity relationship as exists in the total industry.
5. Cost of equity and capital is calculated on an investment weighted basis.
6. Calculation of beta in the cost of equity estimate is based on a statistical technique. Two standard deviations which should capture over 90% of all observations results in a range of cost of equity between 16.5% and 19.7% (for 1980 to 1990) and a range for the cost of capital of between 13.1% and 15.3%.
7. See Appendix II for the details of the derivation of the cost of equity and capital.

ROE's

Similarly, ROE's have been very poor for the upstream oil and gas industry over the same time periods, in particular when compared to the investment weighted cost of equity. We have estimated ROE's for the upstream industry based on the assumption that equity is employed in the upstream sector on the same percentage of total capital as in the total industry. During the 1980's ROE's averaged approximately 8.5% in contrast to the industry's investment weighted cost of equity which averaged 17.9%. An interesting and disturbing perspective on the inadequacy of returns is that the industry would have had to earn approximately an additional $13 billion of net income cumulatively through the 1980's to achieve adequate ROE's.

Figure I.2

Industry returns on equity have fallen well below the cost of equity since 1980



Source: PowerWest, PMA

The capital employed by the upstream oil and gas industry has been influenced by factors other than capital raised or retained for direct investment in exploration and development, notably:

(i) Corporate Acquisitions

- We have attempted to estimate the magnitude of past takeover premiums, and their impact on industry profitability since the mid-1970's (see the following table). The rationale for this investigation is that it is open to debate whether policy makers should be concerned with the profitability of this type of activity. There are sound reasons to believe that the fiscal regime is more appropriately directed towards supporting direct investments in developing the basin. More importantly, however, the argument that industry's chronic lack of profitability is more fundamental in nature--ie., caused by the high cost nature of the WCSB and excessive government takes in a low price environment--is more defensible if the industry's profitability record is adjusted to reflect past corporate transactions.

- Since the mid 1970's, corporate acquisitions in the oil and gas industry have totalled approximately $55 billion. We estimate that these acquisitions have increased the capital employed in the upstream industry by roughly $15 billion, due primarily to the acquisition premiums that were paid in the transactions of the early 1980's.

(ii) Writedowns

- Although a negative to income in that period, writedowns have a positive impact on income in the future. In an extreme scenario if the industry were to write off one half the value of assets on its books, future return on capital and equity would improve dramatically suggesting that the industry had suddenly become profitable. Clearly, an arbitrary, or even a justified writedown of financial accounting book values cannot change the inherent profitability of the industry. We have therefore, on a proforma basis, adjusted upwards capital employed in the industry from writedowns allowing for the normal units of production depletion of these costs.

Table I.2

CANADIAN UPSTREAM OIL AND GAS INDUSTRY
Adjustments of Capital, Income and ROCE for Acquisition Premiums and Writedowns
($Cdn Billions)

Year	Original Capital	Cumulative Acquisition Premiums	Cumulative Writedowns	Net Cumulative Adjustment to Capital	Adjusted Capital	Net Impact on Income + Def. Taxes + AT Interest	New Income + Def. Taxes + AT Interest	New ROCEI	ROCEII
1979	20.3	2.0	0.2	-1.7	18.6	0.3	3.8	20.3	17.8
1980	26.9	2.3	0.5	-1.7	25.2	0.4	4.7	21.4	16.6
1981	34.4	7.8	0.8	-6.9	27.5	0.7	3.7	13.9	9.2
1982	42.1	8.1	1.3	-5.8	36.3	0.9	4.9	15.2	10.1
1983	42.2	8.1	2.4	-4.5	37.7	1.3	5.8	15.6	12.1
1984	52.4	8.3	3.0	-3.9	48.5	0.8	6.3	14.5	10.6
1985	56.7	8.3	3.5	-3.1	53.6	0.7	6.5	12.8	10.2
1986	46.6	8.3	6.6	-0.4	46.2	2.6	1.6	3.3	3.2
1987	49.3	9.0	7.6	-0.1	49.2	0.9	4.1	8.7	6.6
1988	52.2	12.6	8.3	-2.7	49.5	1.0	2.6	5.3	2.9
1989	55.2	14.9	9.0	-4.1	51.1	1.1	2.9	5.7	3.0
1990	54.4	14.9	9.0	-3.4	51	0.6	3.5	6.9	3.7

Notes:

1. **ROCEI - Adjusted for acquisitions and writedowns. ROCEII - adjusted for writedowns only.**
2. Acquisition premiums reflect acquisition prices above the book value of equity or assets acquired for acquirers which have been incorporated into PMA data. Foreign, non-industry acquirers or portfolio acquisitions of stock are not captured in PMA capital data. Non-upstream acquisitions are also excluded.
3. Acquisition premiums are deducted from total capital and writedowns are added back on a proforma basis net of accumulated depletion.
4. Acquisition premiums increase industry depletion and as they are "permanent differences" from a tax perspective, are a direct reduction in net income. (We have assumed that one half the writedowns relate to acquisition premiums and are also a permanent difference). We have assumed on average that depletion of premiums and writedowns occurs over approximately 15 years.
5. Most of the acquisitions were financed by debt, however, because interest is added back to the calculation of ROCE they do not impact upon the return on capital calculation.

The table above provides a breakdown of the adjustments we have made to account for past acquisition premiums and writedowns. Interestingly, over the past decade, writedowns have totalled $9 billion or 60% of estimated acquisition premiums. After recognizing that some amortization and depletion of acquisition premiums occurred over the decade, we estimate that the $54 billion in capital employed by the industry as at year-end 1990 includes $4 billion less of acquisition premiums net of writedowns. The net impact of these adjustments on upstream income in 1990 is approximately $600 million.

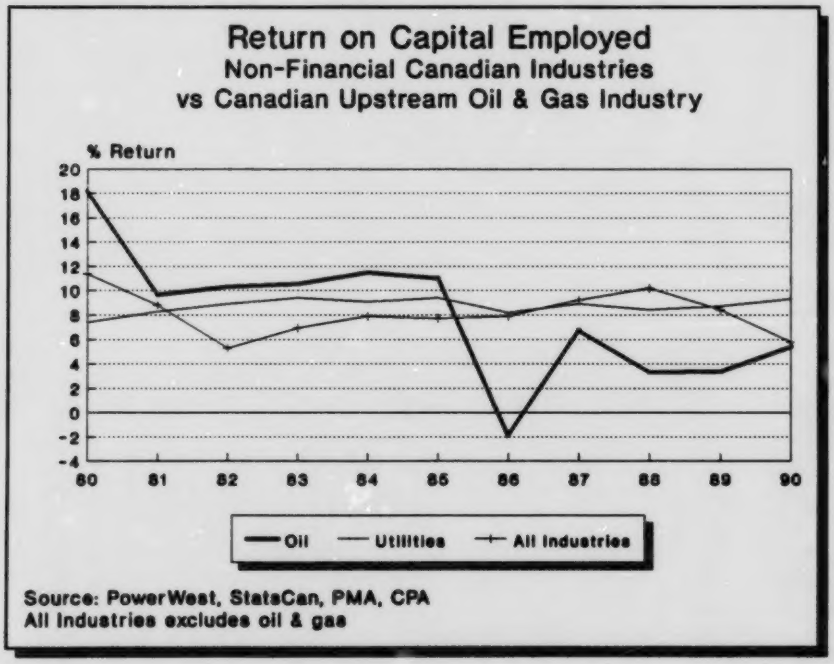
These proforma adjustments significantly alter the profile of profitability for the industry over the first half of the 1980's, raising ROCE's by roughly 3% over the unadjusted ROCE's, to a level commensurate with the industry's cost of capital over this period. ***Importantly, over the second half of the decade and prospectively, these adjustments have a relatively minor effect and do not alter our conclusions about industry profitability over this period.***

Profitability Comparison with Other Industries

Another important perspective on the profitability of the Canadian oil and gas industry is the comparison to returns being earned in other sectors of the Canadian economy. Although the industries differ, the comparisons are relevant and important because the oil and gas industry must compete with the other industries for capital. To put the size of the Canadian oil and gas industry into perspective, capital employed in the Canadian economy as measured by Statistics Canada totalled $661.5 billion at the end of 1990, of which $490 billion was employed in the non-financial sectors of the economy. The upstream industry had total capital employed of $54 billion representing 11% of total non-financial industries capital while the total industry (including downstream operations) had $79 billion of capital employed, representing 16% of the total.

The following graphs compare return on equity and return on capital employed for the oil and gas industry against all other non-financial industries in the Canadian economy. To simplify the presentation, these graphs highlight the returns earned by all industries aggregated (segregated information by industry is provided in Appendix IV). In addition, returns are also compared to the utility sector.

Figure I.3

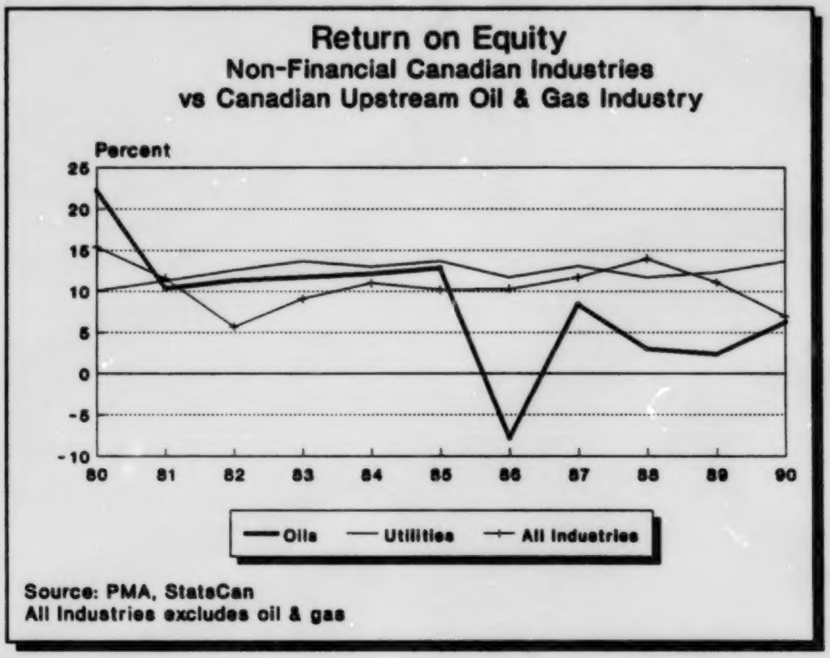


Return on Capital Employed
Non-Financial Canadian Industries
vs Canadian Upstream Oil & Gas Industry

Source: PowerWest, StatsCan, PMA, CPA
All Industries excludes oil & gas

Since 1986, returns on capital employed in the upstream industry have fallen well below those earned in other Canadian industries

Figure I.4



Source: PMA, StatsCan
All Industries excludes oil & gas

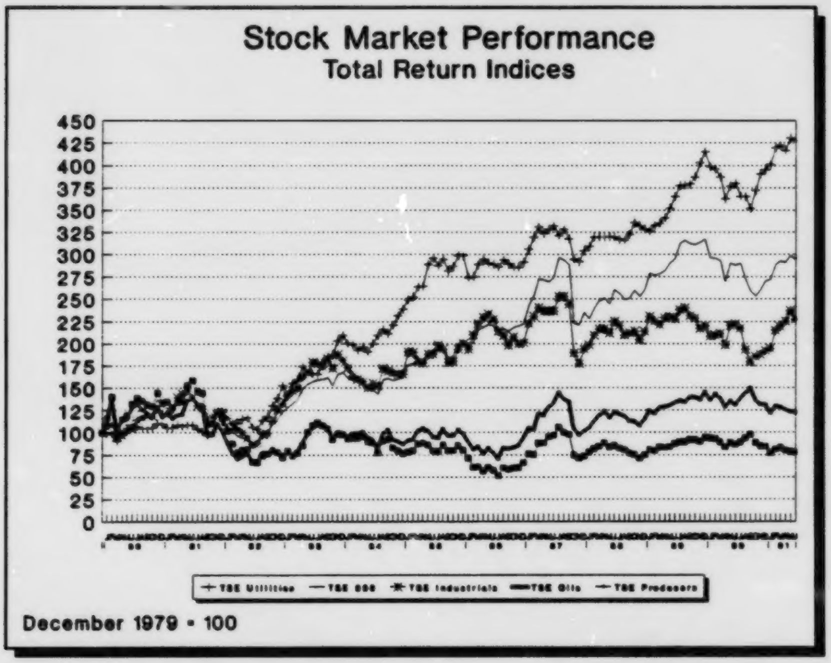
The returns on equity earned by the upstream industry have been much lower than other Canadian industries since 1986

Returns for the oil and gas industry since 1986 have been lower than average industry returns in the Canadian economy and, most disturbingly, have also been less than those earned by utilities. Utilities are regulated and represent the lowest risk and consequently have the lowest return requirement of all the industries in the economy. Since 1986, returns on equity and capital in all the other non-financial industries of the Canadian economy averaged 11% and 8%, respectively. Over the same period, returns on equity and capital in the utility sector averaged 13% and 9%, respectively, versus 2.5% and 3.3% in the upstream sector. The fact that returns for the upstream industry are significantly lower than the utilities is particularly telling as the utility sector is regulated, represents the lowest risk and consequently has the lowest return requirement of all industries.

Recognizing the importance of the risk-return relationship in capital markets, the oil and gas industry should clearly be earning higher rates of return than utilities. Adjusting for the risk inherent in the oil and gas industry as discussed earlier in this section, the rate of return requirement (cost) on equity was nearly 18% through the 1980's versus regulated returns on equity of between 13% to 15% for utilities. Appreciation of the risk premium required for the oil and gas industry is critical in comparisons between industries. Over the past two decades the risk inherent in the oil and gas industry has been greater than the market as a whole (see Appendix II).

An important consequence and confirmation of the poor returns for the oil and gas industry relative to other sectors of the Canadian economy is the poor stock market performance of the oils relative to the overall equity market, the industrials and utilities. Indexing all stock market data to 100 at December 31, 1979, these other groups significantly outperformed both the producers (upstream) and the total oil and gas industry over the past decade. Our experience, supported by financial theory, is that equity markets are efficient and properly reflect value creation (or loss) over time. The efficiency of the market is most apparent when broad trends such as chronic poor profitability prevail over an extended period of time.

Figure I.5



The oils have significantly underperformed the other sectors of the Canadian economy since 1980

The following table summarizes the stock market and return on equity performance for the groups identified earlier. The composition of industry groups in the TSE 300 is a reasonable representation of the companies and industries in the Canadian economy. The TSE 300 also includes financial services and banks which comprise approximately 20% of the float in equity markets. Because of the substantially different nature of financial services companies versus industrial corporations we have excluded them from the return on equity and capital comparisons. Based on market performance, we would surmise that the returns on equity for the industrials and TSE 300 were likely higher than that of the oil and gas group. ***The poor market performance of oil and gas equities fairly reflects the poor fundamentals for the group over the past decade. In addition to the obvious consequence of disappointing returns to the owners of the industry, it also effectively increases the cost and difficulty of raising equity capital to finance growth for the oil and gas industry.***

Table I.3

CANADIAN INDUSTRY RETURNS AND MARKET PERFORMANCE

	Average 1980-1990 ROE	Canadian Market Performance 1980-1990	
		Cumulative	Annual
TSE 300	N/A	175%	9.6%
Industrials	N/A	95%	6.3%
Utilities	12.6	300%	13.4%
Upstream (Producers)	9.1	-25%	-2%
Total Oil and Gas Industry	7.1	25%	2%
Treasury Bills		227%	11.4%

Notes:
1. Average returns on equity have been calculated for the oil and gas industry and utilities for the past decade based on PMA and Statistics Canada data.
2. Returns on equity were not estimated for the Industrials or the TSE 300 owing to the difficulty of sourcing comparable data.
3. Stock market performance data based on the Toronto Stock Exchange overall market index and subindices for the identified industry groups.
4. The upstream (producers) segment does not include the upstream performance of the integrateds.

Profitability Comparison with International Energy Companies

Another relevant and highly important comparison of profitability is to the international oil and gas industry. This is a critical perspective in today's increasingly globalized economy. The most readily available, reliable, and comparable information for this comparison is against the U.S. oil and gas companies.

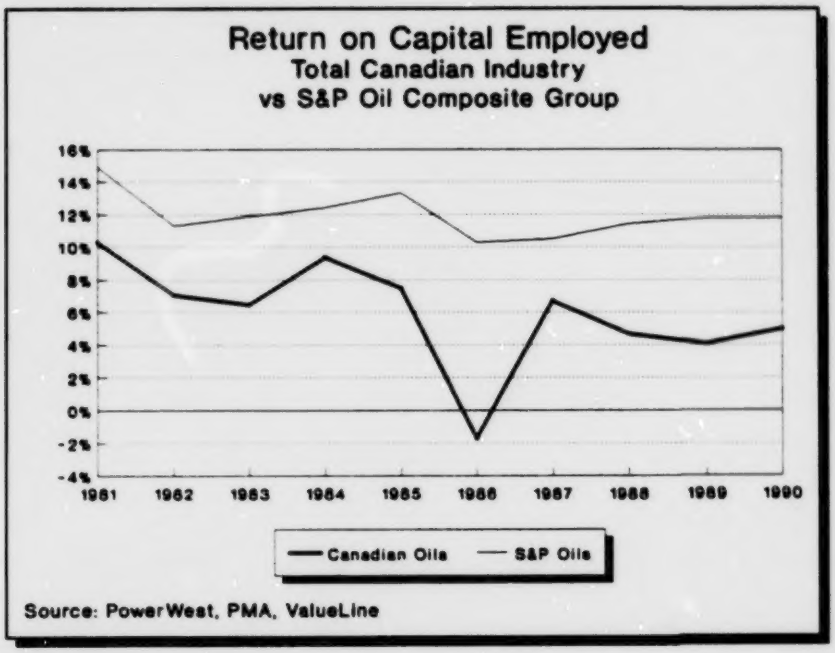
The U.S. does not have oil and gas industry information comparable to the PMA or Statistics Canada. However, the capital employed in the 16 companies comprising the S&P 500 Oil and Gas Index totals approximately $US 236 billion (in contrast to $Cdn 79 billion in the entire Canadian oil and gas industry) and represents a large percentage of the U.S. based oil and gas industry. As the S&P oil and gas companies are actively involved in international oil and gas activities--approximately 53% of their total reserves of 47.8 billion BOEs are outside the United States--this comparison is, in fact, to the broader profitability of the international oil and gas industry. In addition, using the S&P oil and gas companies also allows us to compare stock market as well as corporate returns.

Many of the S&P oil and gas companies are involved in the refining and marketing, and chemical business to a greater extent than the Canadian companies. This may distort the results somewhat, however, we estimate that 55% of capital employed has been invested in the upstream sector. In the Canadian industry approximately 74% of the capital employed has been invested in the upstream sector.

Over the past decade, a period of weak and declining energy prices for the oil and gas industry, the S&P oil and gas companies were able to earn returns on equity that were on average 7.2% higher than the Canadian oil and gas industry and returns on capital that were 6.3% higher. It is interesting that the U.S. industry was able to continue to grow profitably through the decade, even after the collapse in energy prices in 1986. This stands in sharp contrast to the Canadian industry. It is also relevant that the U.S. companies were able to achieve these returns on total equity and capital bases of $US 170 billion and $US 237 billion respectively, approximately three and one-half times the amount of capital invested in the Canadian industry.

Figure I.6

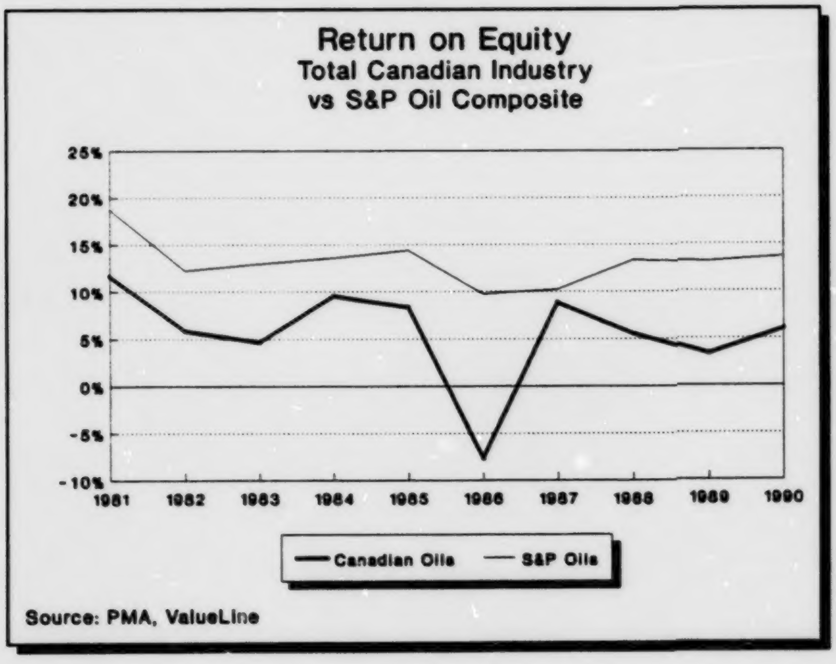
The major U.S. based oil and gas companies have achieved consistently higher returns on capital employed than the Canadian industry



Source: PowerWest, PMA, ValueLine

Figure I.7

Returns on equity are also much higher for the major U.S. based companies

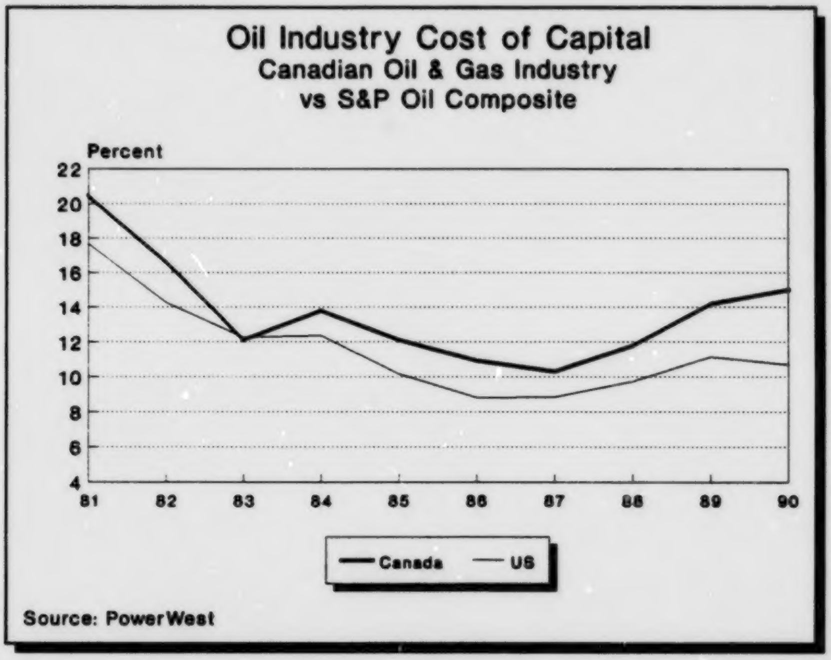


Source: PMA, ValueLine

Further reinforcing the poor performance of the Canadian oil and gas industry is that the cost of capital and therefore required returns are higher for Canadian companies. Risk free returns, U.S. T bills vs. Canadian T bills, have on average been approximately 270 basis points lower in the U.S. market than in Canada through the 1980's. Although the overall market premium in the U.S. has been approximately 7% versus 3.7% in the Canadian market, largely offsetting lower risk free rates, the overall cost of equity and total capital for the S&P Oil and Gas companies over the past decade was approximately 15.1% and 11.6%, which was 2.5% and 2.1% lower than the Canadian industry's cost of equity and capital respectively. The primary reason for this, as higher overall market premiums in the U.S. offset their advantage of lower risk free rates, is the lower risk premium (relative to the overall market) for these U.S. companies which is understandable given their size and diversification. The derivation of the cost of capital for the U.S. companies is included in Appendix II. ***The double negative for the Canadian industry is that not only have they been less profitable, but that the industry also needs to be more profitable to attract capital and justify investment.***

Figure I.8

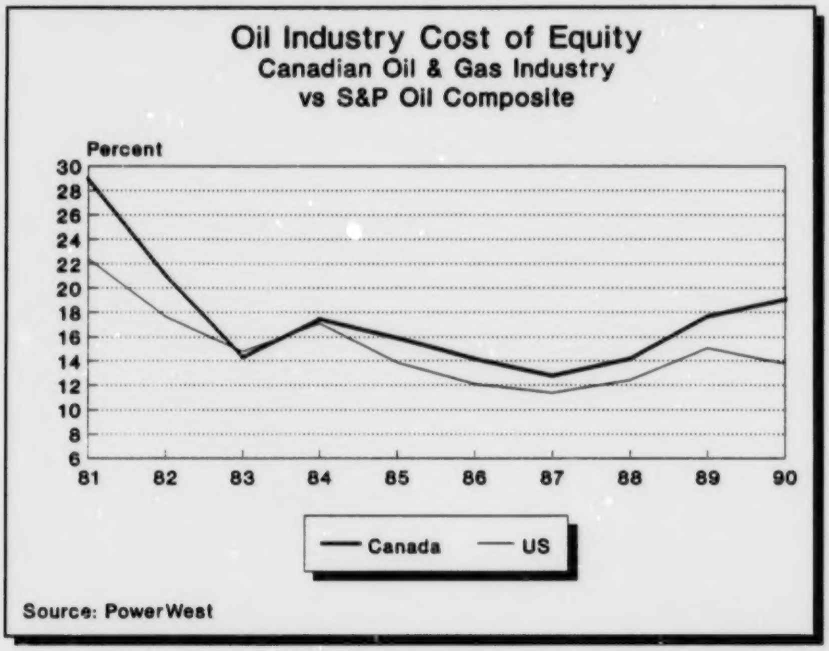
U.S. companies have a lower cost of capital than Canadian companies



Source: PowerWest

Figure I.9

Required return on equity is also lower for U.S. companies


Oil Industry Cost of Equity
Canadian Oil & Gas Industry
vs S&P Oil Composite

Source: PowerWest

Although we cannot identify all the reasons for the different levels of profitability between these two groups of companies, one underlying factor is their relative finding and development (F&D) costs. F&D costs are generally lower internationally than in Canada (as Canada is becoming a higher cost basin--this is discussed in more detail in the next section) with the consequent negative impact on Canadian profitability. Related to higher F&D costs is the poorer record on reserve replacement ratios in Canada with the consequently negative impact on growth. Further negatively affecting profitability in Canada is reserve quality and distance from markets, both of which contribute to lower prices. The crude slate in Canada is becoming heavier and natural gas is farther from average North American markets than for U.S. based companies. The table below summarizes the comparison of F&D costs and reserve replacement ratios between the Canadian and international companies.

One of the obvious consequences of poor profitability has been the relative stock market performance of Canadian versus U.S. and other international oil and gas companies. U.S. oil and gas equities as reflected in the S&P Oil and Gas Index have tripled over the past decade while Canadian oil and gas equities are flat. In our experience, equity markets are efficient and over time properly reflect value. The record of poor profitability in the Canadian oil and gas industry is clearly reflected in capital markets.

Table I.4

Canadian F&D costs rank high in an international context

INTERNATIONAL FINDING AND DEVELOPMENT COSTS

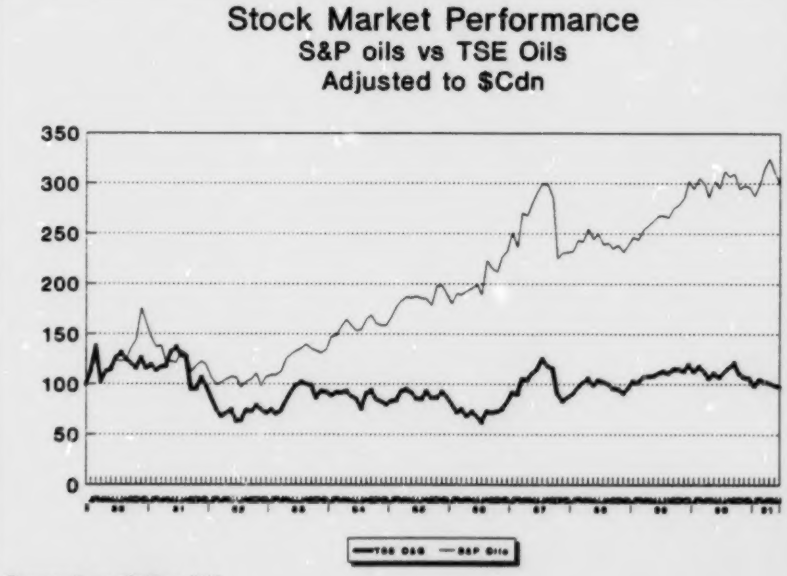
	5-Year Average F&D Costs ($US/BOE)	Capital Expenditures ($US/BOE)	Reserve Replacement
John S. Herold Estimates			
Gas @ 6:1			
Foreign	4.23	5.31	125%
North Sea	4.59	6.01	131%
Worldwide	4.63	4.77	103%
United States	5.16	4.31	83%
Canada	5.92	5.65	95%
Canada @ 12:1	7.85		
PowerWest Aggregate Industry Estimates			
Gas @ 12:1			
Canada	6.83	5.41	79%
United States	5.95	5.39	90%

Source: John S. Herold, PowerWest.

Notes:
1. John S. Herold estimates of U.S., foreign, and world wide F&D costs are the weighted average of 55 companies.
2. John S. Herold Canadian costs are weighted average of 29 companies.
3. John S. Herold North Sea costs are the weighted average of 21 companies.
4. Aggregate industry F&D costs calculated using methodology described in Section II and Appendix V. Source data for Canada from CPA (conventional areas only) 1986-90. U.S. data taken from Energy Information administration (reserves) and American Petroleum Institute (expenditures) over 1985-89 period. Exchange rate adjustment based on average over this period.

Figure I.10

The Canadian oils have significantly underperformed the major U.S. based oil and gas companies



December 1979 = 100
Capital Returns Only

SECTION II

BEHIND THE DEPRESSED RETURNS--WHY HAS THE CANADIAN OIL AND GAS INDUSTRY BEEN UNPROFITABLE?

MAJOR CONCLUSIONS

1. Price expectations, and the extent to which the actual course of prices was misjudged is, in our view, the major factor underlying the poor profitability of the Canadian upstream industry. Forecasts in use during the early 1980's were calling for oil and gas prices to exceed $80/B (WTI) and $6/Mcf respectively, by 1990. These types of forecasts were being used by companies to evaluate exploration prospects, major projects and acquisition opportunities, by investors to evaluate equity values and the longer-term growth potential of the sector and by governments in formulating policies. Economic "realities" caused actual prices to follow a dramatically different course than that which was expected. *Today Canadian producers are receiving an average of $23/B for light oil and below $1.50/Mcf for natural gas. As late as 1985 they had been expecting to receive over $40/B for oil and nearly $4.00/Mcf for gas at this point in time. The impact of lower prices on producer revenues has obviously been very significant. Even though liquids and gas production has increased modestly since 1985, gross upstream revenues have fallen from $29.2 billion to an average of $18.6 billion per year between 1986 and 1990.*

2. *Expectations of high prices and the perceived high value of oil in the late 1970's and early 1980's had a profound impact on the capital base of the Canadian (and world) oil and gas industry.* Approximately 82% of the current capital in place in the upstream sector was formed post-1975. Through the decade of the 1980's, capital employed nearly tripled from about $20 billion to $54 billion. Direct investment in exploration, development and non-conventional projects, and the premiums paid in corporate takeovers, were the primary forces behind the expansion of the upstream industry's capital base.

3. *Despite the tremendous expansion in the upstream industry's capital base, Canadian conventional reserves contracted 10% on a BOE basis and production levels are up only modestly since 1979. Trends in finding and development (F&D) costs are reflective of these poor "physical returns" to investment.* Industry average F&D costs were below $1/BOE from the inception of the industry through to the early 1970's. In the space of ten years, F&D costs increased nearly 10-fold due to the pursuit of higher risk plays and marginal prospects, combined with a general decrease in the prospectivity of the WCSB and higher drilling costs. F&D costs improved considerably over the 1983-1987 period but, disturbingly, now appear to be on the rise again, having moved up over the last few years to over the $8/BOE level based on the latest 5-year average which includes 1990 results.

4. *Depletion and depreciation charges (D&D) are reflective of the capital costs of the reserves produced in any given year and, in the case of the Canadian industry, have a severe impact on earnings.* The D&D charges incurred by the industry on a BOE produced basis have increased nearly four-fold since 1979, from just over $1/BOE to $4/BOE in 1990, largely due to the escalation in F&D costs incurred by the industry over this period. D&D in 1990 was approximately $3.7 billion, representing the second largest expense of the upstream industry.

5. *High operating costs are a major contributor to the poor profitability of the upstream industry, and are also reflective of the high cost nature of the WCSB.* Operating costs have been in a seemingly inexorable upward trend since the early 1970's because of the general aging in the WCSB's largest fields and lower productivity, higher cost additions, growing at an average annual rate of greater than 20% between 1975 and 1985 (on a BOE basis). Although the industry had some initial success controlling costs after the 1986 oil price crash, costs have resumed an upward trend over the past three years, rising to an all time

high of $6.10/BOE in 1990 ($5.4 billion annually). This excludes Alberta's oil sands projects, currently running at about $1.5 billion annually. One of the consequences of high and essentially fixed operating costs is that the Canadian upstream industry as a whole is very levered to changes in prices. ***In the lower price environment of the post-1986 era, operating costs have become by far the industry's largest expense and now account for well over 30% of upstream revenues.***

6. ***The level of government take from the oil and gas industry has also been a major contributing factor to the poor profitability of the industry since 1981.*** Even though industry profitability was deteriorating through the first half of the 1980's, total government take from the upstream industry increased from $6.3 billion to $10.6 billion in 1985 (adjusted for incentive payments). Lower prices have forced governments at all levels to reduce their takes which have fallen to an average of about $3.6 billion per year since 1986. Most of this revenue is received in the form of royalty payments to the provincial governments (primarily Alberta) as income tax payments have been relatively minor in light of low earnings in the sector. ***The key point is that even though the magnitude of the industry's royalty burden is significantly smaller today, there is still a substantial withdrawal of funds from an industry that is not generating acceptable levels of profitability. The economic rent that royalties are supposed to capture does not exist in the current price environment.***

7. ***The high, essentially fixed operating costs, D&D charges, and royalty burdens that the Canadian upstream industry faces magnify the bottom line impact of lower prices.*** Cash flow rose steadily between 1981 and 1985, to about $10 billion annually, then slumped to about the $6-$7 billion range since 1986 and will likely fall well below 1980 levels in 1991. The total earnings of the sector are even more leveraged to prices than cash flow because of high D&D charges. After averaging $3 billion per year between 1980 and 1985, earnings in the sector have plunged to an average of $600 million per year since 1986 and we estimate will be a negligible $200 million in 1991.

8. The Bank of Canada's high interest rate policy since 1987 has had a two pronged negative impact on the oil and gas industry. ***The cost of debt is higher than other industrialized countries.*** This impact translates into higher interest expense, and therefore less income and reduced profitability for the sector. We estimate that the increase in Canadian rates beyond U.S. rates since 1988 has cost the Canadian upstream industry approximately $100 million per year. The more far reaching consequences are higher required returns on capital, increased return requirements from existing assets and higher hurdle rates on future investment, all of which combine to work against capital formation in the sector. ***The Canadian dollar is much stronger than otherwise would have been the case.*** From an all time annual low of 0.72 $US/$Cdn in 1985, the dollar strengthened to 0.86 $US/$Cdn by early 1990 and has remained at about this level ever since. A stronger Canadian dollar has a significant impact on industry revenues because all crude oil and 45% of natural gas sold is priced in U.S. dollars. We estimate that each 0.02 $US/$Cdn increase in the exchange rate costs the upstream sector about $600 million in lost revenue (on an annualized basis). ***The steady appreciation of the Canadian dollar since 1985 has cost the producing industry a total of about $3.5 billion in lost revenue.***

9. ***Industry profitability has also been affected by past corporate transactions.*** Significant premiums over the book value of acquired companies were paid during the transactions of the early 1980's. This contributed to the growth in capital employed by the industry and to higher D&D charges. We have attempted to adjust the actual profitability record of the industry to reflect these transactions. The motivation for this adjustment being that it is debatable if government policy should be concerned with ensuring that returns are earned on such premiums. ***This analysis supports the view that the premiums paid in past corporate transactions are only a minor contributing factor to poor levels of industry profitability since 1985. In terms of the capital side of the profitability equation, the tremendous surge of capital investment into exploration, development and oil sands, and the resultant poor physical and financial returns from these investments have had a much more serious impact on the upstream sector's profitability than corporate acquisitions.***

SECTION II

BEHIND THE DEPRESSED RETURNS– WHY HAS THE CANADIAN OIL AND GAS INDUSTRY BEEN UNPROFITABLE?

INTRODUCTION

The evidence is clear that the upstream sector of the Canadian oil and gas industry as a whole has been unable to meet minimum profitability standards since 1981, and that the situation has deteriorated seriously since 1986. Understanding the reasons for this poor profitability is critical to forming judgements about the outlook and the broader implications that this holds for the sector. We examine this question in this section of the report which is organized as follows. The section opens with a review of the price forecasts that were being used at the corporate decision making level through the 1980's. These expectations played an integral role in shaping investment decisions and government policy initiatives, the impact of which are still being felt today. They also provide a fitting background for the discussion on the specific factors which have affected profitability in the industry. Certain of the key factors we address on the income side are prices, royalties and taxes, operating costs, interest rates and depreciation and depletion. On the capital side, we examine capital spending and specifically the returns, both physical and financial, resulting from these investments. We also address the implications of corporate activity, mergers and acquisitions to industry profitability.

Price Expectations

The long life nature of oil and gas reserves ensures that price expectations play a pivotal role in the industry, intimately affecting investment decisions, corporate strategy, and government policy initiatives. We have compiled a composite of the price forecasts that were used through the 1980's, provided in the following tables.

Table II.1

SUMMARY OF CRUDE OIL PRICE FORECASTS 1980-1991
WTI at Cushing, Oklahoma
$US/B

	Actual Price	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
1980	33.89	33.89											
1981	36.80	37.11	36.80										
1982	33.20	40.63	40.30	33.20									
1983	29.60	44.50	44.12	35.88	29.60								
1984	28.33	48.72	48.32	39.38	31.75	28.33							
1985	27.28	53.35	52.91	43.25	33.50	31.63	27.28						
1986	15.10	58.42	57.93	47.50	36.00	32.63	26.00	15.10					
1987	19.15	63.97	63.44	52.75	39.75	34.75	28.00	19.75	19.15				
1988	15.96	70.49	69.91	58.31	44.25	37.75	29.00	20.88	18.50	15.96			
1989	19.43	77.68	77.04	64.45	49.25	41.00	31.00	22.63	20.25	17.88	19.43		
1990	24.46	85.61	84.89	71.24	54.00	44.75	33.00	24.50	22.25	19.63	18.75	24.46	
1991		94.34	93.55	78.74	59.00	48.50	35.00	26.63	24.38	21.63	20.50	22.25	22.00
1992		103.96	103.10	87.04	64.50	52.50	38.00	28.75	26.50	23.75	22.63	22.50	21.50
1993		114.57	113.61	96.22	69.66	56.38	40.00	31.25	28.88	26.25	25.13	24.50	22.25
1994		126.25	125.20	106.36	75.23	60.65	43.00	34.25	31.50	29.25	28.25	27.50	23.88
1995		139.13	137.97	117.58	81.25	65.24	46.00	37.25	33.88	31.75	31.38	30.50	26.13
1996		153.32	152.04	129.99	87.75	70.18	49.23	40.05	35.88	33.25	33.25	33.50	28.88
1997		168.96	167.55	143.70	94.77	75.50	52.68	42.87	38.13	35.00	34.88	35.25	31.75
1998		186.19	184.64	158.87	102.35	81.22	56.36	45.83	40.38	36.75	36.63	37.00	34.50
1999		205.19	203.48	175.63	110.54	87.38	60.31	49.09	42.75	38.50	38.38	38.75	36.88
2000		226.12	224.23	194.18	119.38	94.01	64.53	52.53	45.50	40.50	40.38	40.75	39.00

Source: Major Calgary Engineering Company.
Note: Prices shown are usually the average of two forecasts produced annually.

Table II.2

SUMMARY OF NATURAL GAS PRICE FORECASTS 1980-1991
Western Gas Marketing Limited With TOPGAS (B1B2)
$Cdn/Mcf

	Actual Price	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
1980	2.42	2.40											
1981	2.46	2.75	2.70										
1982	2.67	2.95	2.85	2.67									
1983	2.61	3.30	3.20	3.40	2.61								
1984	2.78	3.50	3.55	3.80	2.85	2.78							
1985	2.60	3.70	4.05	4.36	3.15	2.85	2.60						
1986	2.15	4.05	4.70	4.88	3.45	3.13	2.80	2.15					
1987	1.57	4.30	5.00	5.40	3.85	3.50	3.00	2.01	1.57				
1988	1.50	4.50	5.15	5.98	4.35	3.95	3.25	2.05	1.63	1.50			
1989	1.37	4.80	5.70	6.53	4.90	4.28	3.50	2.26	1.88	1.58	1.37		
1990	1.46	5.15	6.25	7.12	5.40	4.75	3.70	2.55	2.25	1.83	1.50	1.46	
1991		5.50	6.75	7.87	5.90	5.13	4.00	2.84	2.70	2.23	1.75	1.50	1.40
1992		5.90	7.20	8.72	6.35	5.53	4.20	3.13	3.18	2.68	2.03	1.60	1.40
1993		6.30	7.75	9.65	6.85	5.95	4.50	3.50	3.58	3.13	2.43	1.80	1.53
1994		6.75	8.25	10.70	7.40	6.40	4.80	3.93	4.03	3.60	2.90	2.10	1.70
1995		7.25	8.85	11.83	8.00	6.88	5.15	4.34	4.40	3.98	3.40	2.55	1.95
1996		7.75	9.50	13.12	8.65	7.43	5.50	4.65	4.73	4.30	3.88	3.05	2.25
1997		8.25	10.15	14.52	9.35	7.98	5.90	4.95	5.08	4.58	4.30	3.65	2.58
1998		8.85	10.85	16.07	10.10	8.58	6.30	5.31	5.38	4.85	4.68	4.20	2.93
1999		9.50	11.60	17.80	10.90	9.23	6.75	5.68	5.70	5.10	4.98	4.70	3.25
2000		10.15	12.40	19.72	11.75	9.95	7.20	6.08	6.05	5.35	5.30	5.15	3.55

In hindsight, the forecasts of the early 1980's seem incredulous, calling for oil and gas prices to exceed $200/B and $10/Mcf respectively, by the year 2000. Nonetheless, at the time these types of forecasts were being used by companies to evaluate exploration prospects, major projects and acquisition opportunities, and by investors to evaluate equity values and the longer-term growth potential of the sector.

If we were to substitute the early 1980 forecasts into our industry model, the upstream sector would have been generating average cash flow growth of approximately 25% per year through the 1980's (assuming that all other factors remained the same). Given that the industry was quite profitable over the late 1970's, this type of outlook indicated that it would have been extraordinarily profitable through the 1980's. With these types of expectations it is no surprise that the industry was so vibrant in the late 1970's and early 1980's. Canadian governments at all levels were also well aware of these implications and were quick to introduce measures to extract their share of the "perceived" economic rent that would result in this type of business environment (discussed in more detail below).

The Reality of Lower Prices

As everyone involved in the industry is all too aware, the high prices of the late 1970's and early 1980's introduced powerful economic forces--conservation, substitution, new supply technologies. The economic "realities" caused actual prices to follow a dramatically different course than that which was expected during that period. To put this into perspective, today Canadian producers are receiving an average of $23/B for light oil, and less than $1.50/Mcf for natural gas. As late as 1985 they had been expecting to receive over $40/B for this oil and nearly $4.00/Mcf for gas at this point in time.

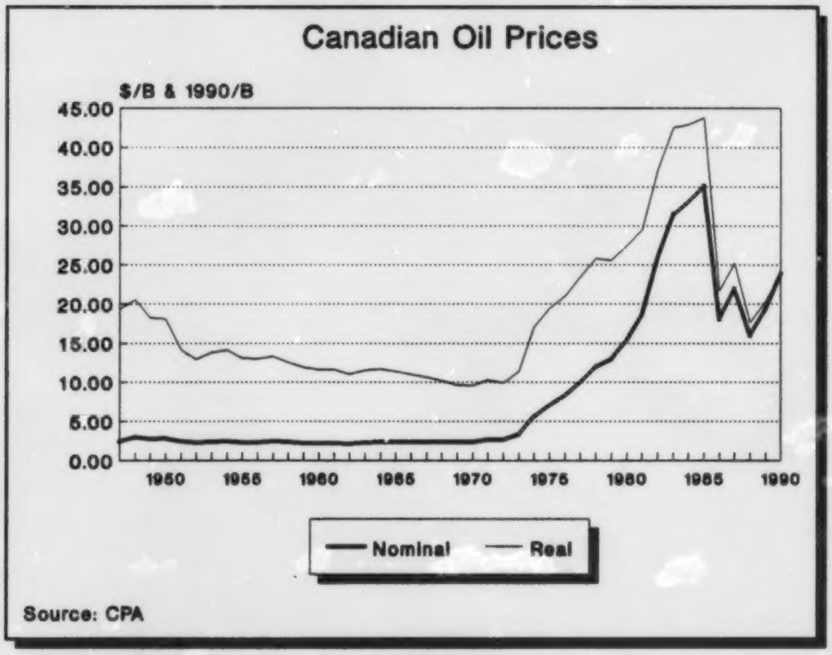
It is important to note that Canadian oil and gas prices were regulated from the early 1970's to late 1985. Producers had been pressing to receive market prices for some time and were finally granted their wish in 1985 when crude oil prices were formally deregulated in June under the Western Accord. Since then posted prices have been based on the prices being paid by U.S. refiners for Canadian supplies and essentially track the prices of the world's major marker crude, West Texas Intermediate at Cushing Oklahoma. The Agreement on Natural Gas Markets and Prices late in 1985 formally initiated gas price deregulation. Export prices had been partially deregulated by the NEB in 1984 but were still subject to several tests. Full deregulation of prices within the producing sector went into effect in November 1986.

De-regulation fully exposed producers to lower prices

Looking back over the 1980's, the irony of deregulation is readily apparent.

- *Canadian oil producers were denied world oil prices during the peak years of the early 1980's only to be deregulated just in time to bear the full brunt of the 1986 oil price collapse.* Canadian oil prices slumped from $35/B in 1985 to an average of just over $20/B over the 1986-90 period. This decline has been magnified recently by a trend of widening quality differentials. This trend became evident in 1990 when the spread between light and heavy grades of crudes--proxied by the differential between Petro-Canada's light sweet and Hardisty Heavy reference crudes--averaged well over $6/B, versus a traditional level of roughly $4/B. Several factors have contributed to a further substantial widening in differentials to date in 1991. Through the first six months of the year, Canadian light/heavy differentials have averaged just over $9/B, roughly $5/B above longer-term historical levels.

Figure II.1

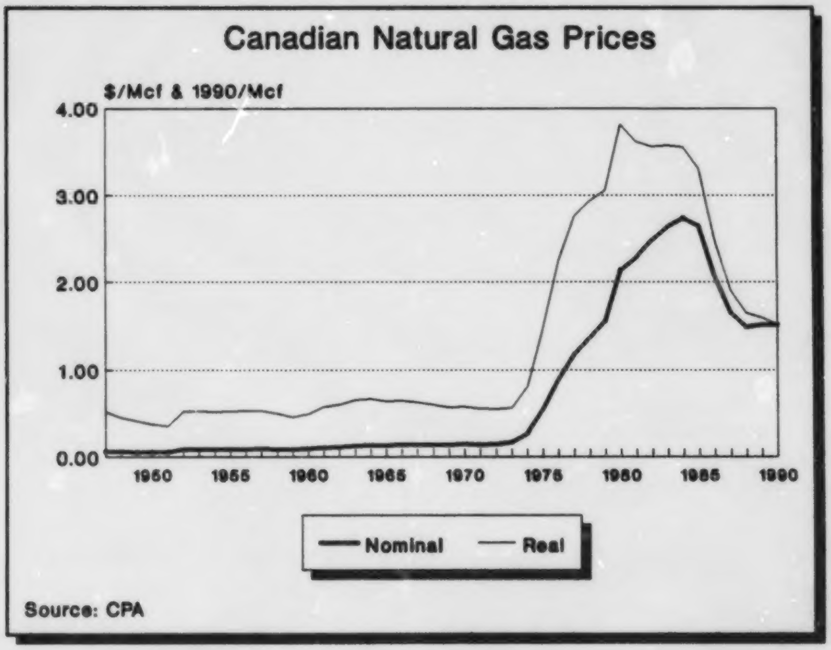


Source: CPA

Current oil prices are roughly equivalent to the prices being received in the late 1940's after adjusting for inflation

- ***Gas prices in Canada and the U.S. were both deregulated in an excess supply environment that was almost solely the result of the distortions introduced by past regulatory oversight. The resulting gas-on-gas competition has exerted steady downward pressure on prices since the mid-1980's.*** Canadian gas prices averaged $2.80/Mcf in 1985, fell to $2.20/Mcf in 1986 and then slipped to about the $1.55/Mcf level between 1988 and 1990. The consensus view at the time was that this was the bottom of the market but a very warm winter in 1990 (and several other factors) has led to a precipitous drop in both Canadian and U.S. spot prices in 1991. Through the first half of the year, we are estimating that the average Alberta wellhead price is approximately $0.20/Mcf below 1990 levels. U.S. prices are down roughly $US 0.30/Mcf from 1990 levels.

Figure II.2



Source: CPA

In real terms, Canadian gas prices are currently less than half of levels received during the early 1980's

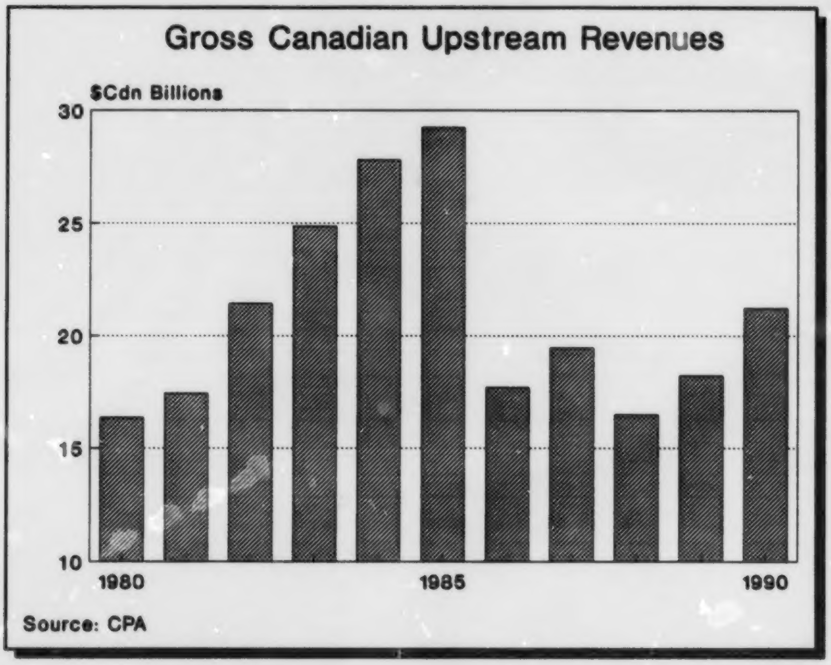
Compounding the impact of lower prices since deregulation has been the steady strengthening of the Canadian dollar over the same period. The exchange rate has a pervasive impact on the prices that Canadian producers receive as all oil and about 45% of the natural gas sold is priced in U.S. dollars. From the low of $0.72 US/Cdn in 1985, the dollar strengthened to $0.86 US/Cdn by early 1990 and has remained at about this level ever since. As crude oil and nearly half of the natural gas sold by the industry is priced in U.S. dollars, a stronger Canadian dollar has a significant impact on industry average prices and revenues. The details of this impact are discussed later in this section.

A stronger Canadian dollar has magnified the recent weakness in international energy prices

The impact of lower prices on producer revenues has obviously been very significant. Total liquids revenues have fallen from a record high of $20.7 billion in 1985 to a range of $10.8 billion (1988) to $15.6 billion (1990), averaging $12.9 billion over the 1986-90 period. Lower prices were somewhat offset by modest growth in liquids production which increased from 1.7 MMB/d in 1985 to about 2.0 MMB/d over the last three years. Most of this growth, however, occurred in lower-value heavier grades and natural gas liquids (NGLs). Light oil production has slipped from 1 MMB/d in 1985 to just over 900 MB/d in 1990.Natural gas revenues slumped from $7.8 billion in 1985 to a low of $4.8 billion in 1987, and have since remained fairly stable at about $5.1 billion per year. Since 1986, dramatic growth in sales volumes, from 2.5 Bcf to 3.4 Bcf in 1990, has nearly managed to offset falling prices.

Figure II.3

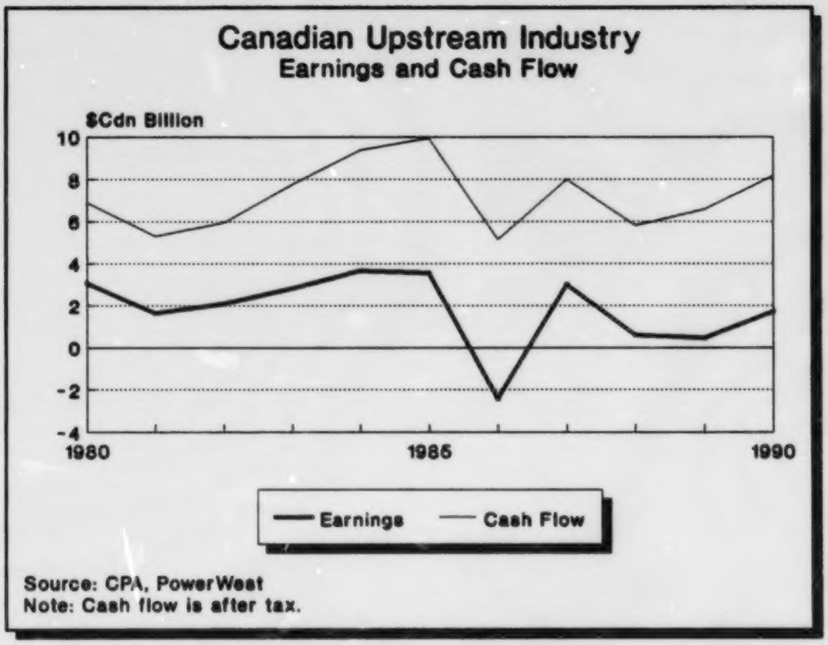
Gross upstream revenues since 1986 are down nearly 30% from the 1982-85 annual average



Source: CPA

Given this tremendous contraction in revenues and the high, essentially fixed operating cost, depletion and royalty burdens that the industry faces (see below), the bottom line impact on earnings and cash flow has been more significant than the drop in revenues. After rising steadily between 1981 and 1985, to about $10 billion annually (for upstream operations only), cash flows have slumped to about the $6-$7 billion range and will likely fall well below 1980 levels in 1991. The total earnings of the sector are even more leveraged to prices because of the very high depreciation and depletion charges that the industry now incurs because of the massive capital expenditures over the past decade (also discussed below). The net income of the industry, which averaged $3 billion per year between 1980 and 1985, has plunged to about $600 million per year since 1986.

Figure II.4


Canadian Upstream Industry
Earnings and Cash Flow

Source: CPA, PowerWest
Note: Cash flow is after tax.

Upstream industry earnings and cash flow are very exposed to lower prices because of high, essentially fixed operating cost, depletion, and royalty burdens

A New Pricing Environment?

Oil price forecasts were revised down every year during the 1980's, except for 1990 when the Gulf Crisis and the underlying tightness in world oil markets led to a slightly more positive longer-term outlook for crude oil. Gas price forecasts came down every year over this period. Unlike oil, however, the prolonged gas surplus and persistent low prices have led to sharp downward revisions in short and long-term gas price expectations over the past year. Consensus forecasts are now calling for WTI prices to reach about the $40/B level in 2000, down from $60/B plus expected in 1985 and the $200/B range expected in the early 1980's. Gas prices are now expected to reach the mid $3/Mcf level by 2000, versus the $10/Mcf plus expected through the first half of the 1980's.

This steady downward trend in price expectations has forced the industry to consider the very real possibility that prices will remain relatively flat for the foreseeable future. Much of the current rationalization taking place in the industry is focused on dealing with this prospect. This concern is well founded. As we show in Section IV, the outlook under such a scenario is quite bleak.

THE FISCAL REGIME

Government Shares of Upstream Revenues

The level of government take from the oil and gas industry has also been a major contributing factor to the poor profitability of the industry since 1981. The total government share of the upstream sector's operating income (total revenues less operating costs, excluding interest expense and adjusted for incentive payments) was as high as 55% in 1979, approximately $5.6 billion, a period when the sector was profitable. However, even though industry profitability began to worsen through the first half of the 1980's, government's income share remained between 45%-55%, ranging from $6.3 billion in 1980 to $10.6 billion in 1985. Since 1986, lower prices have forced governments at all levels to reduce their takes. Governments now take about 30% of the upstream revenue. The absolute level has varied considerably, from $3.8 in 1986 to $2.6 billion in 1988.

Federal Government Takes and Policies

The Federal government historically received its share of the upstream sector's income through income taxes. The tax treatment of the industry historically was quite generous, allowing for accelerated write off of certain capital expenditures (notably the earned depletion feature of the pre-1981 regime). The industry's effective tax rate was as a result generally well below statutory rates. However, in October 1980 in response to the buoyant price expectations of the late 1970's and the associated potential for increased economic rent, the federal government introduced the National Energy Program, which included the following significant measures: 1) the Petroleum Gas and Revenue Tax (PGRT), which was a flat rate tax on net operating revenue and was not deductible for income tax purposes; 2) the phase out of earned depletion; and 3) the Petroleum Incentive Payment Program, a system of grants offered on the basis of Canadian ownership for exploration and development, with the focus being to promote expenditures on frontier lands.

Table II.3

CANADIAN UPSTREAM INDUSTRY REVENUE SHARES
($Millions)

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	Average 1986-90
Industry												
Cash Flow Before Interest	7,901	6,245	7,423	8,732	10,095	11,094	7,177	8,478	7,203	7,850	9,337	8,009
PIP and other Incentive Grants	0	920	1,600	1,760	1,920	1,760	1,010	2,92	266	139	0	341
Land Payments to Crown	-1,003	-830	-530	-710	-940	-1,330	-490	-793	-659	-486	-598	-605
Total	6,898	6,335	8.493	9,782	11,075	11,524	7,697	7,977	6,810	7,503	8,739	7,745
% Share	52.2%	47.4%	50.9%	51.1%	51.7%	52.1%	66.7%	65.2%	72.0%	70.4%	65.8%	68.8%
Provincial												
Royalties and Freehold Tax	4,281	4,620	5,340	5,700	5,950	5,730	3,140	2,628	2,222	2,436	2,810	2,647
Land Payments	982	820	520	700	930	1,320	490	793	659	486	598	605
Corporate Income Tax	105	196	171	385	605	549	16	151	-160	-40	228	39
PIP and Other Incentives Paid	0	-410	-520	-410	-410	-500	-340	0	0	0	0	-68
Total	5,368	5,226	5,511	6,375	7,075	7,099	3,306	3,572	2,721	2,882	3,636	3,223
% Share	40.6%	39.1%	33.0%	33.3%	33.1%	32.1%	28.6%	29.2%	28.8%	27.1%	27.4%	28.2%
Federal Share												
PGRT	0	1,060	2,070	2,100	2,450	2,270	452	0	0	0	0	90
Corporate Income Tax	934	1,231	1,687	2,242	2,303	2,482	757	970	191	408	903	645
Land Payments and Royalties	21	10	10	10	10	10	0	0	0	0	0	0
PIP and Other Incentives Paid	0	-510	-1,080	-1,350	-1,510	-1,260	-670	-292	-266	-139	0	-273
Total	955	1,791	2,687	3,002	3,253	3,502	539	678	-75	269	903	463
% Share	7.2%	13.4%	16.1%	15.7%	15.2%	15.8%	4.7%	5.5%	-0.8%	2.5%	6.8%	4.0%

Source: PMA.
Note: ARTC is netted out of provincial income tax.

The PGRT was an extremely burdensome tax and constituted a direct drain on cash flow

The impact of these measures was immediate and far reaching. PGRT payments in 1981 were just under $1 billion in 1981 and rose to an average of $2 billion per year between 1982 and 1985. The tax was phased out under the Western Accord in 1985 but producers still paid out nearly $500 million in 1986. In total, the industry paid roughly $10.4 billion in PGRT over the period it was in effect. These payments were extremely burdensome to the industry and constituted a direct drain on cash flow. In terms of the profitability of the industry, if the PGRT had not been in effect, the industry's aggregate ROCE would have been about 2%-3% higher over the 1981-85 period, in line with the industry's cost of capital.

The impact of the PIP program was more subtle but had a much longer lasting effect on the industry. The program itself did not directly impact the revenues of the industry as the accepted accounting approach was to credit the payments against the capital expenditures for which they were received. PIP payments were, however, a substantial source of off balance sheet financing to the industry, providing $900 million in 1982 rising to a peak of $1.5 billion in 1984 (excluding provincial payments). Final payments of $200 million were made in 1986 under grandfathered agreements.

The PIP program introduced distortionary incentives which still impact industry profitability today

As discussed below, this source of essentially free capital stimulated spending on projects that provided very poor returns, particularly in the frontier regions. Expenditures in these areas doubled between 1981 and 1983 to well over $2 billion per year. Even though the capital actually placed on balance sheets was considerably lower than these expenditures because of the accounting treatment, it still weighs on current returns because no income will be generated for the foreseeable future. Another less apparent impact of the PIP program is the incentives it provided for Canadian companies to acquire foreign owned firms. This is also discussed below in more detail in the discussion of corporate transactions.

Even after adjusting for PIP payments, the PGRT dramatically increased the federal government's share of industry revenues, from about the 9% level to the 15% plus range through the first half of the 1980's. The elimination of the PGRT and the very poor profitability of the industry since 1986 has dramatically lowered the take of the federal government, to about the 5% level, arising almost solely from income taxes.

Federal incentive programs have lapsed while a surtax and LCT have been introduced to increase tax revenues

The federal government has taken several steps to reverse this trend. Incentives schemes which were introduced in the aftermath of the 1986 price crash such as the Canadian Exploration and Development Incentive Progam (CEDIP) and Canadian Exploration Incentive Program (CEIP) have been discontinued. Investment tax credits have also been phased out as was the earned depletion allowance. The statutory federal income tax rate has been lowered from 35% to 28%. However, a "temporary" 3% surtax has seemingly become permanent and a large corporations tax (LCT) has been introduced. This tax is essentially based on the assets of a company and is paid even if there are no taxable earnings. The oil and gas industry is particularly affected by the tax because of the capital intensiveness of its operations.

Provincial Government Takes

Provincial governments take their share of income from the upstream sector of the oil and gas industry in the form of crown royalties, mineral taxes and land payments for exploration and production leases. Total payments to provincial governments in 1979 (net of incentives) were about $4.6 billion or 46% of total industry income in 1979. Several incentive plans were introduced between 1980 and 1985, following the implementation of the NEP and the subsequent deterioration in industry profitability, including increased Alberta Royalty Tax Credit, reduced royalties, drilling grants, royalty holidays, etc. The impact of all these programs steadily reduced the provincial governments share of upstream income to about 32% by 1985.

Following the price crash of 1986, provincial governments further reduced royalty rates and several new incentive programs were introduced to stimulate investment levels (most notably drilling incentive programs and royalty holidays). Combined with the impact of lower prices on royalty rates and land bonuses, the provincial share of income has been fairly stable in the 27-29% range since 1986, but at a much lower absolute level. The annual take has been in the order of $3 billion per year since 1987, versus in excess of $7 billion in 1984 and 1985.

We would note that there are now very few incentives available to the industry to defray expenditures. All of the programs introduced after 1986 have been terminated, although some wells will enjoy royalty holidays for a few more years into the future. In addition, the Alberta Royalty Tax Credit (ARTC) has been reduced. There have also been some modifications to the royalty treatment of enhanced oil projects. Essentially these changes lowered the costs that companies could deduct from the revenues being generated by these projects, increasing the effective royalty rate.

The economic rent that royalties are supposed to capture does not exist in the current price environment

Even though the magnitude of the industry's royalty burden is significantly smaller today, the key point is that there is still a substantial withdrawal of funds from an industry that is not generating acceptable levels of profitability. The economic rent that royalties are supposed to capture does not exist in the current price environment. In fact, since the price crash of 1986, government takes could have been completely eliminated and the upstream sector would still have been unable to generate a ROCE above 10%.

Controls on Gas Export Volumes

The federal government regulates the export of natural gas through the National Energy Board (NEB), a process that began with the National Energy Board Act in 1959. Through to 1987, gas exports were only allowed if they satisfied a "surplus test" that determined whether the proposed volumes were in excess of reasonably foreseeable future Canadian requirements. The tests used to quantify the surplus evolved considerably over time and were eventually removed altogether in 1987. The NEB now regulates gas exports under very broad guidelines that do not pose a barrier to commercial arrangements.

Past controls on exports mandated that the Canadian industry maintain excess supply capability. Through the 1970's, the Canadian reserves to production ratio averaged about 30 years, in sharp contrast to the 10-year reserve life that U.S. producers have long maintained. There is a cost to holding reserves in the ground, just like there is a cost of holding any type of inventory. This cost is very difficult to quantify but it can be shown that a producer faced with a 20-year reserves life must sell his gas at nearly twice the price of a producer with a 10-year reserves life to generate the same rate of return (assuming the reserves cost the same to find and develop).

The consequences of export regulation are readily apparent in the current marketplace. Even with the growth in demand since 1987 and the reduction in gas directed drilling activity through the mid 1980's, the surplus in productive capacity is still very sizable. We estimate that current Canadian productive capacity exceeds demand by nearly 1 Tcf on annual basis. Canadian producers are now aggressively seeking to lower their reserves-to-production ratios to the 10-15 year range. This aggressive marketing strategy is a major reason for the current weakness in Canadian gas prices.

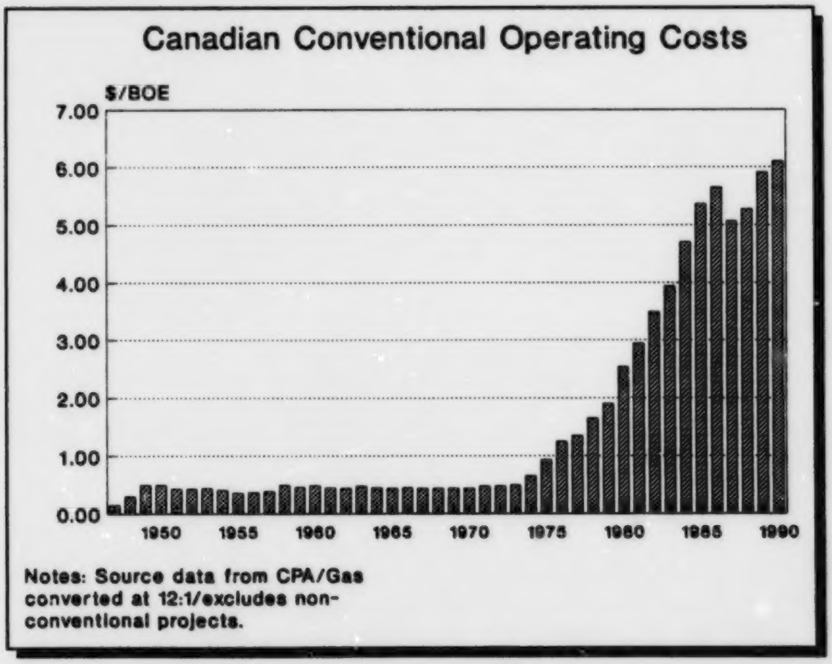
Operating Costs

Like all other costs incurred by the upstream sector, operating costs increased dramatically following the surge in international oil prices in the mid 1970's. Between 1955 and 1974, average operating costs for conventional oil and gas production increased from $0.36/BOE ($50 million annually) to $0.66/BOE ($606 million), an average yearly increase of just over 3% (this includes general and administration expenses). Over the next 10 years conventional operating costs grew at an annual average rate of greater than 20%, and by 1985 had reached $5.37/BOE ($4.4 billion annually).

In the low price post-1986 era, the industry had some initial success controlling costs in 1987 and 1988, lowering the average to just over $5/BOE. Disturbingly, however, costs have renewed an upward trend over the past three years, rising to an all time high of $6.10/BOE in 1990.

Operating costs have proven to be very difficult to control and have renewed an upward trend over the past three years

Figure II.5



Canadian Conventional Operating Costs

Notes: Source data from CPA/Gas converted at 12:1/excludes non-conventional projects.

The costs of operating Alberta's oil sands projects (ie., Syncrude, Suncor's plant, Cold Lake, etc.,) are also very substantial, currently running about $1.5 billion annually, but have come down significantly on a per barrel basis from the late 1970's and early 1980's. During the initial phases of start-up average operating costs were in the order of $15-$20/B. In 1990, average operating costs were $12.59/B, also up from a 13-year low of $10.60 in 1987.

Operating costs are by far the most significant expense that the upstream industry currently faces

One of the consequences of the high, essentially fixed nature of operating costs is that the Canadian upstream industry as a whole is very levered to changes in prices. Over the 1980-85 period, operating costs were the second largest expense facing the industry (after royalties), accounting for 18%-22% of total revenues. ***In the lower price environment of the post-1986 era, operating costs have become by far the most significant component of costs, now accounting for well over 30% of upstream revenues.***

The steady growth in long-term operating costs, in particular the increases in recent years in the context of flat to declining revenues, is a source of great concern to the industry. Several companies are now taking vigorous measures to deal with the problem (discussed further in Section III). ***The factors behind the growth in operating costs are complex and varied, but are primarily due to the general evolution of the Western Canadian Sedimentary Basin (WCSB) into a high cost petroleum basin.***

- Average production per well has fallen dramatically over the past 20 years. Average crude production per operated oil well has fallen from about 96 B/d in 1970 to about 38 B/d in 1990. Average production per gas well declined to a much greater extent, from 1.7 MMcf/d in 1970 to about 0.3 MMcf/d in 1990. To achieve today's marginally higher production levels, there are now over four times as many producing wells as there were in 1970.

- This decline in average output per well is a function of the lower productivity of more recent discoveries and the general decline and deterioration of the older, formerly prolific fields. These aging fields require special care, equipment and generally more surveillance to optimize production levels.

Growth in operating costs is reflective of the evolution of the WCSB into a high cost petroleum basin

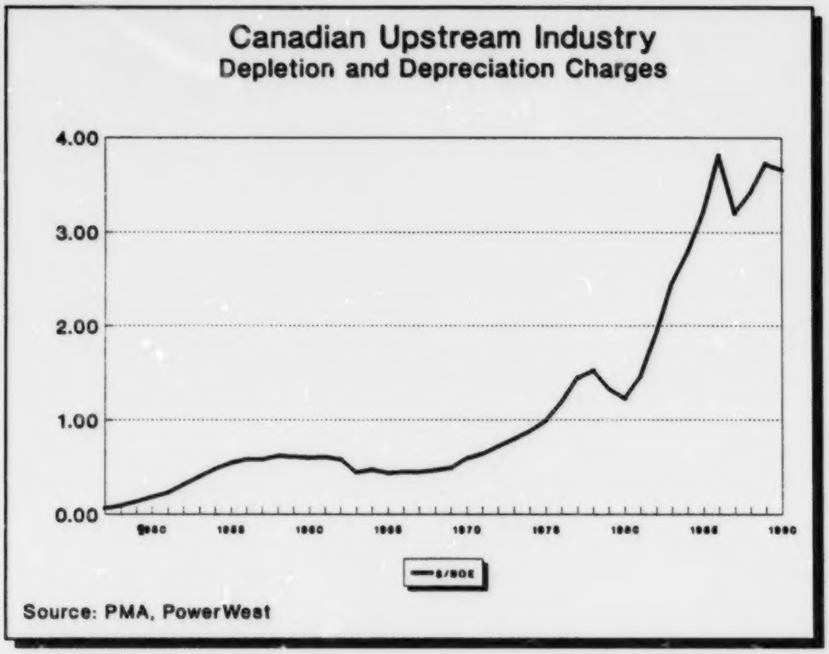
- Most of the large oil fields in the WCSB have moved into a secondary phase of enhanced recovery (ER) schemes. ER projects can improve recovery factors considerably--the ERCB estimates that ER in some pools can increase the average recovery for all pools in Alberta from 19% to 27%. However, these projects are also much more costly to operate than primary production--because of additional power expenses, extra manpower, infill drilling, increased engineering time etc.,--and also require significant investment in facilities.

- Newer discoveries can have the same fixed costs as older fields but these costs are spread over a much smaller production base. More recent discoveries also tend to be heavier than older fields. Operating costs for heavier gravity crudes are higher due to the greater power requirements for lifting, more workovers and because the management of heavy oil production is more manpower intensive.

Depletion and Depreciation Charges

Although depletion and depreciation charges (D&D) are a non-cash item, they nonetheless are reflective of the capital costs of the reserves produced in any given year and have an impact on earnings. In the case of the Canadian industry, the impact has become very severe. The D&D charges incurred by the industry have increased nearly four-fold since 1979, from just over $1/BOE to $4/BOE in 1990.

Figure II.6



Source: PMA, PowerWest

Rising D&D charges are a direct consequence of rising F&D costs

Rising D&D charges are reflective of the explosion in capital spending since 1975 and the dramatic increases in finding and development costs that occurred over the same period (see below for a discussion of these trends). To a much smaller extent, they are also due to the premiums that have been paid in past corporate takeovers (see discussion at end of this section).

D&D is, today, the second largest expense of the upstream industry, behind operating costs. These charges create significant leverage in the upstream industry's earnings to changes in prices. Barring massive writedowns, D&D charges are set to grow significantly in the future. The poor finding and development costs through the 1980's have created a certain momentum that will be very difficult to halt unless future spending is drastically curtailed.

High Cost of Debt

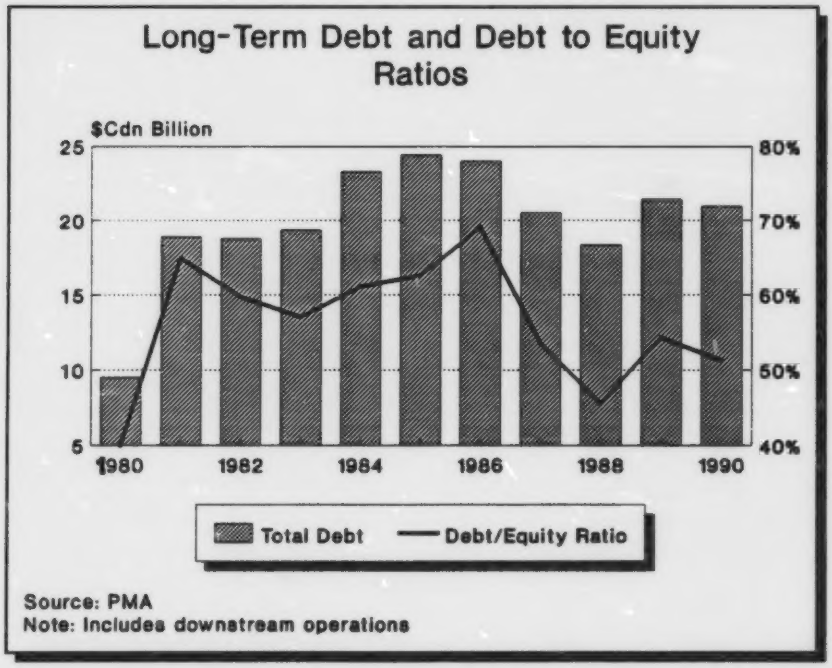
The corporate transactions of the early 1980's had an immediate impact on the net income of the upstream sector as these transactions were financed primarily by debt. In 1980, the entire oil and gas industry (including downstream operations) was carrying a total of about $9.5 billion of long-term debt on the aggregate balance sheet. This nearly doubled in 1981 to $18.9 billion largely due to these corporate takeovers. Very little equity was used to underpin these transactions as evidenced by the sharp increase in the debt-to-equity ratio of the industry, from .40 in 1980 to .65 in 1981.

At the same time the industry was taking on all this debt, the Canadian economy was entering a severe recession. The Canadian government had adapted a very tight monetary policy to control inflation which had been running at 10% per year for the previous two years. As a result, interest rates had soared to nearly 20% in 1981 and remained at about the 15% level in 1982. The interest expense of the industry followed suit, more than doubling from about $800 million in 1980 to $1.8 billion in 1981, and increased a further $900 million in 1982 to $2.7 billion. These additional expenses are one of the principal reasons behind the rather abrupt drop in industry profitability early in the decade.

Since 1981, the industry has generally employed more equity than debt in its financings. The equity base has increased 37% between 1981 and 1990--despite a $4.3 billion writedown in retained earnings during 1986--while long-term debt is up only 13%. As a result the aggregate debt-to-equity ratio stood at about .50 in 1990, down from about the .60 level in evidence through the first half of the 1980's. Over this period the interest expense attributable to the upstream industry has varied between $1.3 billion (1990) and $1.7 billion (1986), accounting for approximately 6% to 10% of total upstream revenues.

Figure II.7

Dramatic increase in industry debt during the early 1980's coincided with record high interest rates



Source: PMA
Note: Includes downstream operations

In 1988, the Bank of Canada embarked on a tight monetary policy to drive down Canadian inflation rates. This policy pushed the central bank rate up nearly 400 basis points between 1987 and 1989, to an annual average of 12.3%. Monetary tightening continued through 1990, pushing the central bank rate over 13%, and has only recently begun to ease. In contrast U.S. rates moved up only modestly over this period, by about 130 basis points.

The Bank of Canada's high interest rate policy has had a two pronged negative impact on the oil and gas industry.

- *The cost of debt is higher than in other industrialized countries.* This is not quite as obvious as it seems, however, as roughly half the industry's debt is under fixed terms and placed in other countries. Approximately one-third is floating debt held in Canada, in most cases by the less senior companies who lack the presence to access foreign debt markets. Nonetheless, we estimate that the additional increase in Canadian rates beyond the increase in U.S. rates has cost the Canadian oil and gas industry $100-$150 million per year since 1988.

- *The Canadian dollar is much stronger than otherwise would have been the case.* As previously discussed, from the low of 0.72 $US/$Cdn in 1985, the dollar strengthened to 0.86 $US/$Cdn by early 1990 and has remained at about this level ever since. A stronger Canadian dollar has a significant impact on industry revenues because all crude oil and 45% of natural gas sold is priced in U.S. dollars. We estimate that each 0.02 $US/$Cdn increase in the exchange rate costs the upstream sector about $600 million in lost revenue (on an annualized basis). Since 1985, the appreciation of the Canadian dollar has therefore cost the producing industry approximately $3.5 billion in lost revenue.

The Capital Component of the Profitability Equation

Expectations of high prices and the perceived high value of oil in the late 1970's and early 1980's had a profound impact on the capital base of the Canadian (and world) oil and gas industry. In 1979, PMA data indicates that the industry had approximately $20 billion in capital employed in the upstream sector of the business. By 1985, the capital employed by the upstream industry had more than doubled to just under $57 billion. Even with the very significant writedowns in 1986, there was still $54 billion in capital employed during 1990. Direct investment in exploration, development and non-conventional projects, and the premiums paid in corporate takeovers, were the primary forces behind the tremendous expansion of the upstream industry's capital base.

Investment

The oil and gas industry responded aggressively to the lure of high values for oil and gas reserves through the late 1970's and early 1980's. Nearly every company operating in the country dramatically increased capital spending over this period. Total annual capital expenditures on exploration and development by the industry increased from $6.0 billion to $10.6 billion between 1979 and 1985 for a cumulative total of $56.1 billion. To put these numbers into perspective, the industry invested a total of $27.7 billion between 1955 and 1978, roughly half the 1979-85 total. A further $34 billion has been invested since 1985 (through 1990), also outstripping the 1955-1978 total.

The physical returns to investment--reserves and production--have been poor through the 1980's

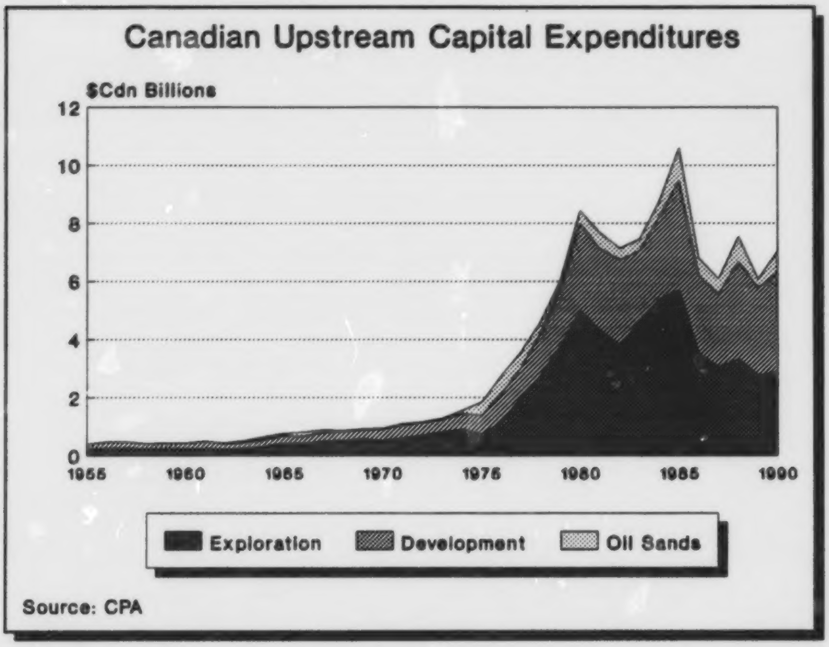
Despite the tremendous growth in capital investment and drilling activity levels since 1979, industry reserves and production levels--the physical returns to investment--have essentially remained flat.

- The conventional crude oil reserve base has contracted by 38% since 1979. NGL and gas reserves are up 72% and 6% respectively, but the reserve base actually contracted by just under 10% on a BOE basis.

- Total conventional output excluding syncrude and bitument production) in 1990 is essentially unchanged from 1.8 MMB/d to 2.0 MMB/d since 1979 levels (on a BOE basis). Declines in light oil production have effectively been offset by growth in lower value heavy oil, NGLs, and natural gas.

Figure II.8

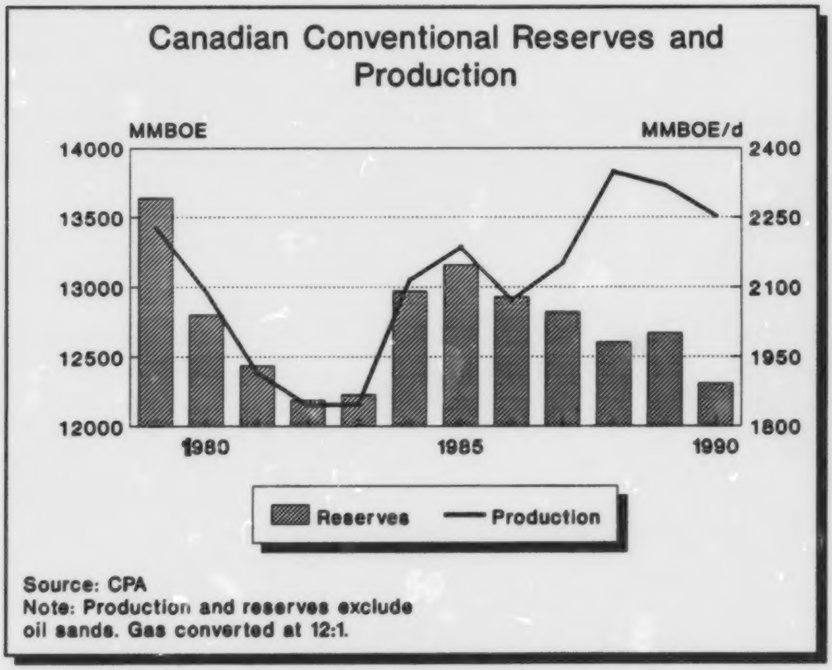
Upstream industry investment since 1979 has totalled $90 billion; three times the total investment over the previous 40 years



Source: CPA

Figure II.9

Despite high investment levels, conventional reserves have contracted and production is up only modestly



Source: CPA
Note: Production and reserves exclude oil sands. Gas converted at 12:1.

Why were the physical returns to the massive investments between 1979 and 1985 so poor? Three broad factors seem primarily responsible.

(i) *The deliberate choice to pursue high risk wildcat exploration and capital intensive heavy oil projects.*

- Exploration expenditures increased from roughly $2.7 billion in 1978 to $5.7 billion in 1985. Much of this investment was directed towards the high risk conventional prospects and high cost and very prospective frontier regions in Northern Canada and the East Coast offshore.

Overly optimistic price expectations led to high risk exploration activity and capital intensive oil sands projects

- PIP grants offset some of the expenditures and effectively reduced the capital that firms had to carry on their balance sheets. Even with this offset, dry hole expenses were significant over this period because of the emphasis on wildcat and frontier exploration. For those companies following the full cost accounting approach, the undepleted portion of these costs would still be on balance sheets, weighing down current returns.

- Numerous capital intensive heavy oil projects were pursued--Cold Lake, Peace River and Wolf Lake were the most notable developments--and expansions to both Syncrude and Suncor's tar sands plants were undertaken. Expenditures on Alberta's oil sands resource were essentially negligible up to the mid 1970's but have been averaging greater than $500 million per year since 1975.

(ii) *Increases in drilling costs due to the tremendous expansion in capital investment during the late 1970's.*

- Growth in drilling activity post 1978 did not match the rise in investment because of corresponding increases in the cost of drilling. The combination of high rig utilization (in the 80% range) and companies bidding against each other for available rigs drove up drilling costs by 250% between 1975 and 1981 (on a per foot basis). Costs came down through the mid-1980's but have been on an upward trend over the past three years.

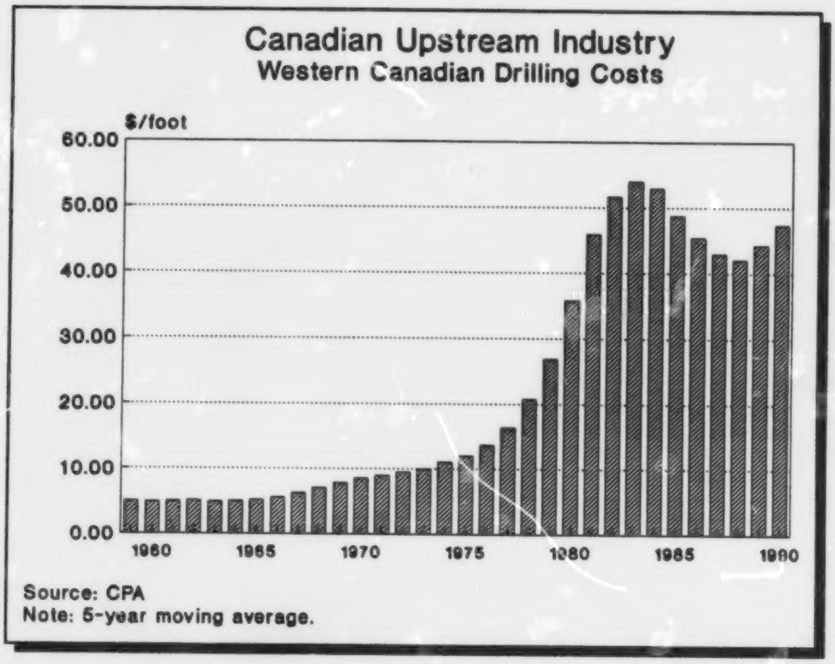
(iii) *The maturation of the Western Canadian Sedimentary Basin (WCSB).*

- The prospectivity of the WCSB has greatly diminished over the past forty years, particularly for crude oil. To illustrate the declining returns to drilling, we have calculated finding rates for oil, gas and on a barrel of oil equivalence (BOE) basis--defined as gross reserve additions per successful well--over the period 1955-1990 (natural gas finding rates include NGL's). The results of this analysis are presented graphically below.

- Between 1955 and 1970, the industry was finding an average of about 440 MB of crude per successful oil well. Crude finding rates began to decline precipitously in the mid 1970's, to about the 100-200 MB/well range, and fell well below 100 MB/well in the early 1980's. There has been some improvement in recent years--to just under 100 MB/well--reflecting industry's high grading of prospects in a low price environment.

Figure II.10

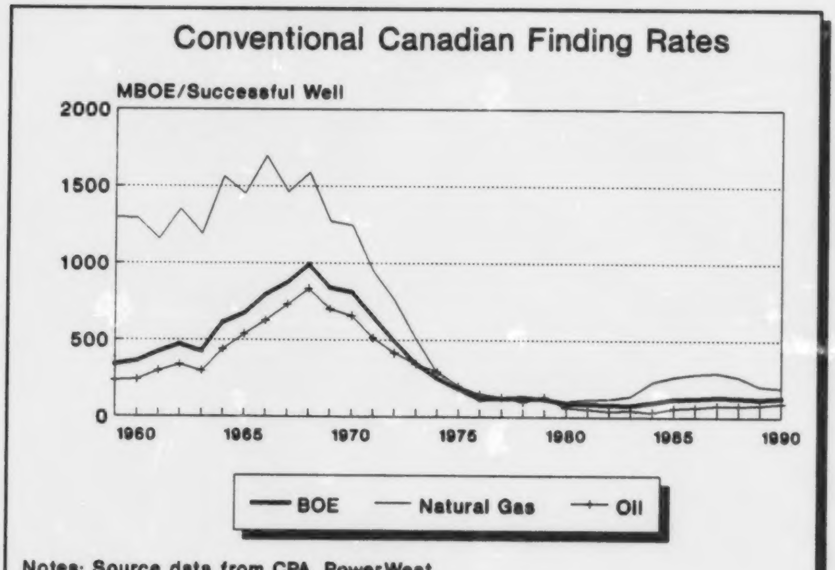
Drilling costs increased five-fold between 1975 and 1985



Source: CPA
Note: 5-year moving average.

Figure II.11

The physical returns to drilling in the WCSB have greatly diminished over the last 20 years



Notes: Source data from CPA, PowerWest Methodology/Gas converted at 12:1/ Results provided are 5-year MAVG's.

- While Shell's recent success at Caroline and several promising discoveries in Northeast B.C. indicate that the gas potential of the WCSB remains significant, average finding rates have also declined dramatically since exploration began in the basin. Gas finding rates exceeded 1000 MBOE/well (10 Bcf/well on a dry gas basis) between 1955 and 1970. After falling significantly between 1975 and 1985, gas finding rates have recovered to about the 200 MBOE/well range (1.3 Bcf/well on a dry gas basis).

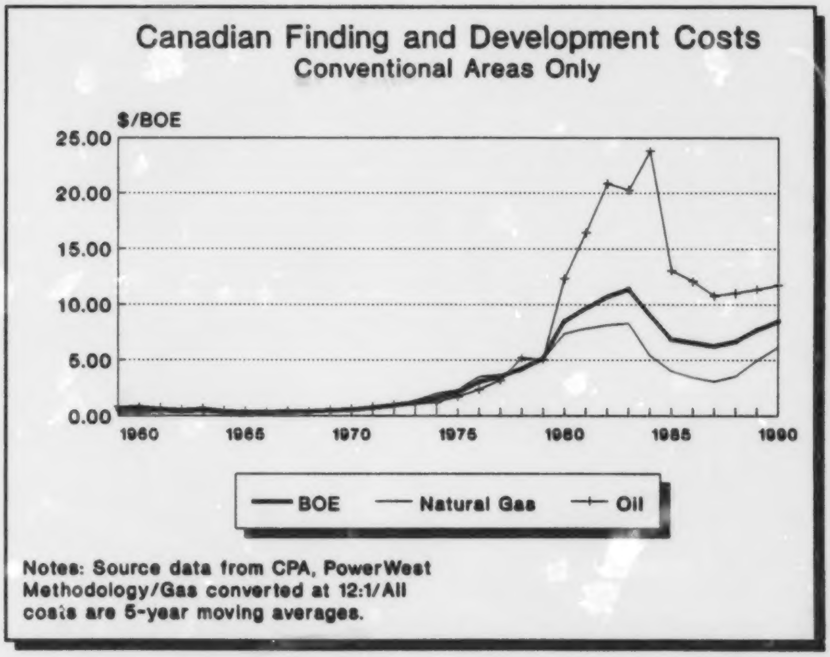
Trends in F&D costs reflect the maturing of the WCSB

Trends in finding and development (F&D) costs are also a good indicator of the maturing nature of the WCSB. We calculate industry F&D costs using the same general methodology we apply at the company level (see Appendix V). While acknowledging that there is much debate about the merits of different approaches to calculating F&D and even as to how meaningful the results of such analysis are, we feel our simple approach provides an accurate indication of cost trends when examined over a long time period.

Our F&D cost analysis is depicted graphically below on a five year moving average (MA) basis. The results are very stark and somewhat disconcerting. Industry wide F&D costs were below $1/BOE from the inception of the industry through to the early 1970's. In the space of ten years, however, F&D costs increased nearly 10-fold due to the pursuit of higher risk plays and marginal prospects combined with the reduced prospectivity of the WCSB and rising drilling costs. F&D costs peaked in the early 1980's at over $11/BOE but then moved down considerably over the 1983-1987 period to about the $6-$7/B level. Importantly, however, costs now appear to be on the rise again, having moved up over the last few years to just over the $8/BOE level based on the latest 5-year MAVG which includes 1990 results.

Figure II.12

Canadian F&D costs have resumed an upward trend over the past few years



Notes: Source data from CPA, PowerWest Methodology/Gas converted at 12:1/All costs are 5-year moving averages.

There is tremendous variation in F&D costs across the companies operating in Canada. Top performers generally are profitable

These aggregate numbers and the observation that they have moved up slightly in recent years are supported by our company work (see Appendix V). We would note that there is, however, tremendous variation across companies. The 1986-90 Canadian F&D costs (excluding foreign expenditures) for the 22 largest publicly traded Canadian companies ranges from $4.00-$19/B with a weighted average of nearly $7.40/B in 1990. *We would make the point that those companies that are in the top quartile of this group have the potential to be profitable and grow in the current price environment.*

There is no doubt that there were and still are countless projects in Canada–exploratory, development, non-conventional, frontier–that would be economic under the type of price environment envisioned in the late 1970's and early 1980's. As we are all to well aware, however, prices failed miserably to live up to these expectations. Although most investments made over this period were based on rigorous NPV analysis and originally looked to provide very significant returns, the reality is that in today's market environment much of this capital is providing very poor returns.

Canadian versus U.S. F&D Costs

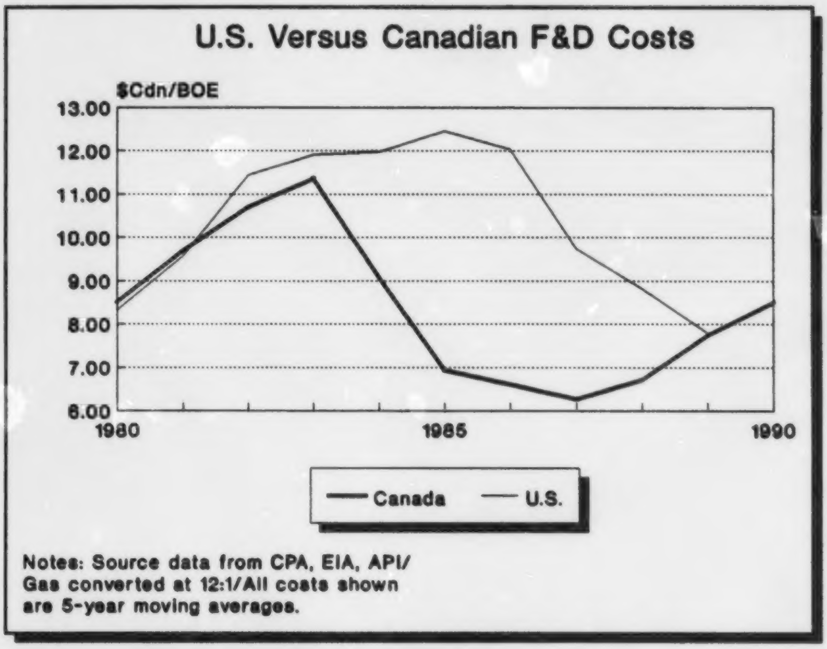
An important perspective introduced in Section I is that Canadian F&D costs rank high in an international context. This conclusion is supported by an analysis of industry average F&D costs in the U.S. Working with aggregate data similar in scope to that provided by the CPA, we find that although U.S. F&D costs were generally higher than Canadian costs through most of the 1980's (after an exchange rate adjustment), they have been on a steady downtrend since 1985. The five year U.S. average in 1989 was $Cdn 7.80/BOE, virtually identical to the Canadian average over the same period, and is likely to trend down in 1990 based on preliminary estimates of reserve additions. It should be noted that gas reserve additions in the U.S. were converted using a 12:1 ratio. In fact, the more appropriate ratio in the U.S. is closer to 10:1 as average wellhead prices are considerably higher due to the closer proximity of U.S. supply basins to markets. Making this adjustment lowers the five year 1989 U.S. average to $Cdn 7.40/B. We would emphasize that Canadian producers need to have lower F&D costs to effectively compete with U.S. producers, largely because Canadian oil and gas wellhead prices are generally lower than U.S. prices because of higher transportation costs.

Average U.S. F&D costs are now about the same or lower than Canadian costs

The conclusion that U.S. F&D costs are currently the same or slightly lower than Canadian costs is somewhat surprising. It is commonly contended that Canadian F&D costs are lower largely because the WCSB is generally viewed as having been much less intensively explored than the major U.S. basins. Although considerably more research in this area is warranted, we believe part of the explanation lies in the more responsive nature of the U.S. upstream industry. Total capital investment in the U.S. fell 22% between 1981 and 1985. In contrast, Canadian producers, who were shielded from falling oil prices by regulation, increased annual investment by nearly 40% over this period. Since the oil price collapse in 1986, annual U.S. upstream capital investment has fallen to less than half the 1980-85 average while Canadian upstream investment are down only 20%. In addition, the U.S. has several basins which offer the potential for large discoveries such as the Gulf Coast offshore, Rocky Mountain, and Arkoma basins, not to mention the recent success in developing coal bed methane reserves.

Figure II.13

Disturbing contrast in F&D cost trends over the second half of the 1980's



Notes: Source data from CPA, EIA, API/ Gas converted at 12:1/All costs shown are 5-year moving averages.

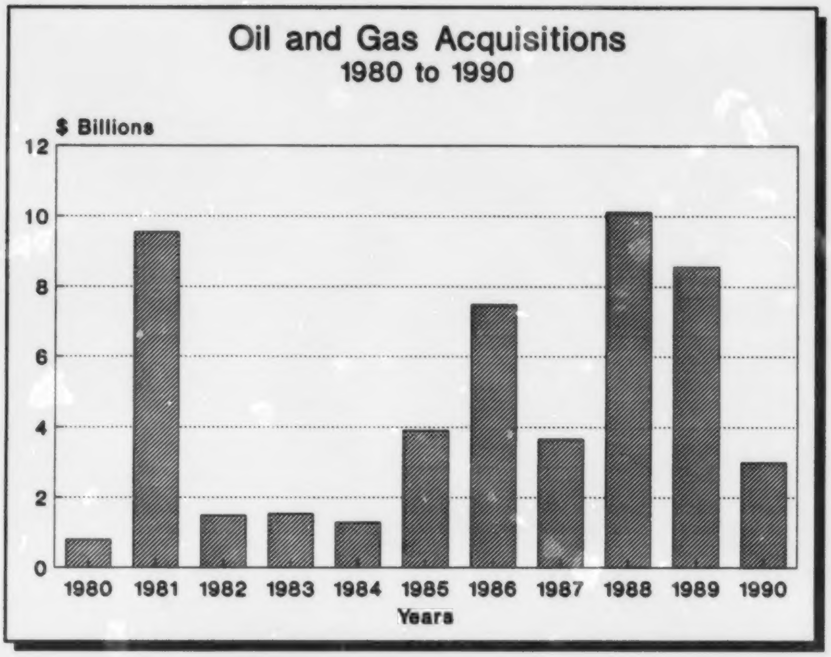
Corporate Transactions

The capital employed by the oil and gas industry has also been affected by past corporate transactions. In the context of the data that is compiled by the PMA, if one company sells its assets to another for a premium over book value, the acquiree stops reporting while the acquirer begins to report based on the actual consideration paid. The premium paid would show up in the aggregate data as additional capital employed by the industry. The financing of the transactions and the additional capital on the balance sheet would impact the income statement.

Since the mid-1970's, the Canadian oil and gas industry has seen two major cycles of corporate transaction activity--1981-82 and 1986 to the present. We are primarily concerned with the first cycle as significant premiums over book were paid during this period. This period of corporate activity can be broadly characterized as a phase where Canadian controlled companies were attempting to expand their presence in the sector. This trend was greatly influenced by the policy stance of the federal government at the time, in particular the PIP program which provided incentives to Canadian controlled firms that were not available to foreign companies. This created an incentive for foreign companies to sell and for Canadian companies to buy.

Between 1976 and 1980, the total value of corporate takeovers was approximately $4.3 billion (10 transactions). In 1981 and 1982, there were 23 transactions for a total consideration of over $11 billion. Dome Petroleum was by far the most active acquisitor over this period. The company acquired five companies between 1979 and 1981 for a total consideration of $5.9 billion, the largest being the acquisition of Hudson's Bay Oil and Gas for $4 billion (which actually closed in 1982). Petro-Canada and the Canadian Development Corporation were the other two major acquisitors over this period, involved in transactions totalling $3.3 billion and $2.2 billion, respectively.

Figure II.14



The second phase of corporate activity, which began in 1986 and is still ongoing today, has been driven by the need to adapt to a lower price environment. Numerous financially distressed firms have been acquired by companies with stronger balance sheets. Given the relatively optimistic longer-term expectations that were held for gas markets over this period, several transactions were driven by the desire of the acquirer to gain an increased exposure to natural gas. More recently there has been an emphasis on property rationalization. Firms are divesting themselves of small working interest positions which provide only a very small contribution to assets and income yet which require a disproportionate share of General & Administrative expenses. This "rationalization" process is discussed in more detail in Section III.

Corporate acquisitions negatively impacted industry profitability in the early 1980's but are no longer a contributing factor

We have adjusted the actual capital employed by the industry to reflect all the major corporate transactions of the 1980's (a detailed table of the adjustments was provided in Section I). This is a very complex task, complicated by the different accounting approaches in use, the lack of information on several large transactions, the allocation of the consideration between downstream and upstream assets and the many write downs that have occurred since 1986 to name but a few of the difficulties. The appropriate adjustments to both the capital employed and the income of the industry over the 1980 to 1990 period have the effect of raising ROCE's by roughly 3-4% over the early 1980's, and by approximately 1% in the second half of the 1980's.

We feel this analysis is supportive of the view that the premiums paid in past corporate transactions were a contributing factor to the poor profitability of the Canadian oil and gas sector, but only in the early 1980's. Reasonable adjustments show that profitability was not out of line with the cost of capital over the first part of the decade. These adjustments, however, fall well short of explaining the extremely poor profitability in the industry since 1986. In terms of the capital side of the profitability equation, the tremendous surge of capital investment into exploration, development and oil sands, and the resultant poor physical returns to these investments have had a much more pronounced impact on the upstream sector's profitability.

SECTION III THE IMPACT OF POOR PROFITABILITY

MAJOR CONCLUSIONS

1. **Upstream capital spending has contracted significantly since the oil price crash of 1986. Through the 1980-1985 period, the industry invested an average of $8.3 billion per year in exploration and development. Average annual expenditures since 1986 have fallen 20%, to an average of $6.7 billion per year. The contraction in investment is much more significant when adjusted for inflation. In 1990 dollars, annual investment levels since 1986 are nearly 40% below those over the first half of the decade.**

2. **The drop in capital expenditures has had a severe impact on those areas of the oil and gas industry which provide services to the upstream sector. The groups that have been most severely hurt by lower levels of investment are the oilfield service, supply and equipment manufacturing industry (the service industry), the drilling industry, and geophysical firms. These groups are reliant on the activity of the oil & gas exploration and production companies as their sole source of revenue.**

3. **Many of the major producing companies have been forced to shed redundant staff to reduce operating and overhead costs to improve competitiveness in a low price environment. Based on media reports, we estimate that approximately 8,000 to 9,000 jobs (including some losses in downstream operations) have been eliminated since 1989. There has also been tremendous job loss in the drilling sector where the workforce has contracted by 50% since 1985, to less than 7,000 employees in 1990. In our view, the current round of staff reductions is particularly telling because it represents a fundamental change in the corporate structure of the industry and as yet shows no signs of abating.**

4. **The importance of the oil & gas industry to the Alberta economy can not be understated. The deterioriation in the sector's profitability since 1980, however, has significantly reduced the contribution of the upstream sector to the provinces economy. This reduced contribution has had a substantial impact on the Alberta economy.**

   - **Alberta's economy significantly underperformed the Canadian economy between 1980 and 1990. Over this period, the Alberta economy expanded by less than 10% in real terms. In sharp contrast, the rest of the Canadian economy grew by nearly 40%.**

   - **The provincial government's revenue sources have been essentially flat since 1986. However, over this same period government spending has been rising by about 5% per year. The result has been a persistent annual deficit that has averaged $2 billion per year since 1987.**

5. **Our main conclusion is that the low level of profitability for the upstream oil and gas industry has had a profoundly negative impact on all stakeholders in the industry: shareholders and investors (generally), the people who work within or depend on the industry for their livelihoods, and on the major producing province of Alberta. The link between profitability and industry growth, employment levels and the industry's contribution to the general economy is undeniable. Low levels of profitability through the 1980's has forced the industry to downsize, reducing its capacity to employ people and contributing to a reluctance to commit additional capital to the sector. While a detailed analysis of this emerging trend to the Alberta economy is beyond the scope of this report, we believe it raises some extremely important and sobering questions.**

SECTION III THE IMPACT OF POOR PROFITABILITY

INTRODUCTION

This section of the report examines the impact of poor profitability and proffers some broad views and questions on the implications for the future. We also discuss the upstream industry's response to poor profitability. This is the Rationalization and Restructuring process which began in earnest in 1986 and which remains a strong force shaping the Canadian oil and gas industry.

NEGATIVE CONSEQUENCES OF POOR PROFITABILITY

Poor Capital Market Performance and Support

This point was emphasized in Section I as evidence and confirmation of the poor profitability of the upstream sector but it can also be interpreted as an inevitable consequence of the same phenomenom. Today, the TSE Oil and Gas Index is up only 25% (total returns) since the end of 1979. In contrast, TSE Composite Index has risen nearly 200% over this period. Most disturbing, perhaps, is the fact that oil and gas indices on the world's two major stock exchanges have been relatively good performers. The S&P oils, for example, more than tripled over the past decade.

Reduced Capital Spending

Upstream capital spending has contracted significantly since the oil price crash of 1986. Through the 1980 to 1985 period, the industry invested an average of $8.3 billion per year in exploration and development. Average annual expenditures since 1986 have fallen 20%, to an average of $6.7 billion per year. The contraction in investment is much more significant when adjusted for inflation. In 1990 dollars, annual investment levels since 1986 are nearly 40% below those over the first half of the decade.

Adverse Affects on Service Industry

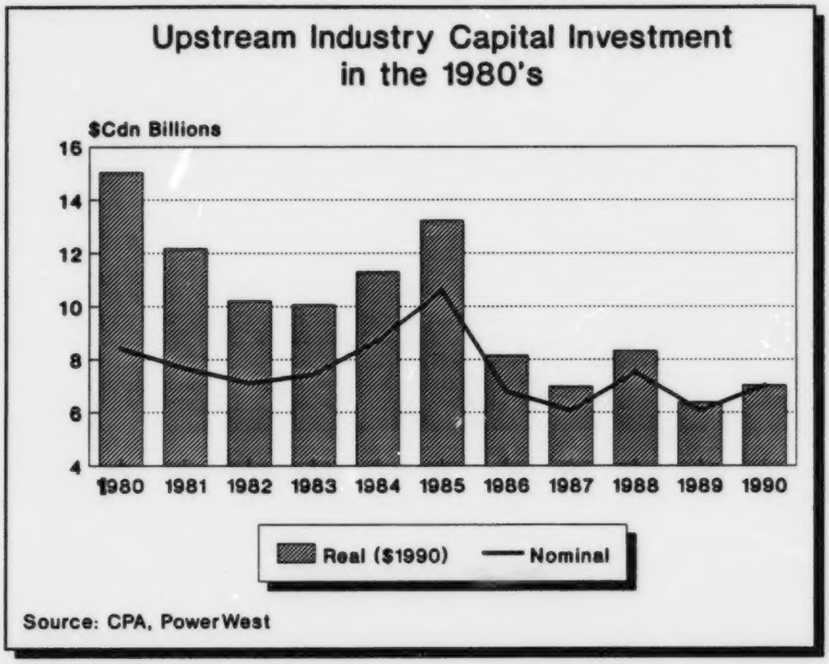
The drop in capital expenditures has had a severe impact on those sectors of the oil and gas industry which provide services to the upstream sector. Those groups that have been most severely hurt by lower levels of investment are the oilfield service, supply and equipment manufacturing industry (the service industry), the drilling industry, and geophysical firms. These groups are reliant on the activity of the oil & gas exploration and production companies as their sole source of revenue.

The service sector is operating at record low levels

To elaborate, the cutback in exploration and development spending has dramatically reduced the drilling activity in Western Alberta. Since 1986, the drilling sector has been able to keep only 35% of its rigs active. The drilling contractors as a whole require rig utilization of 55% to break even and 65% to be profitable. The very poor profitability and low cash flows in the drilling and service sector prevents companies from pursuing badly needed capital upgrades. A great deal of the machinery, equipment and drill strings are near the end of their useful life.

Figure III.1

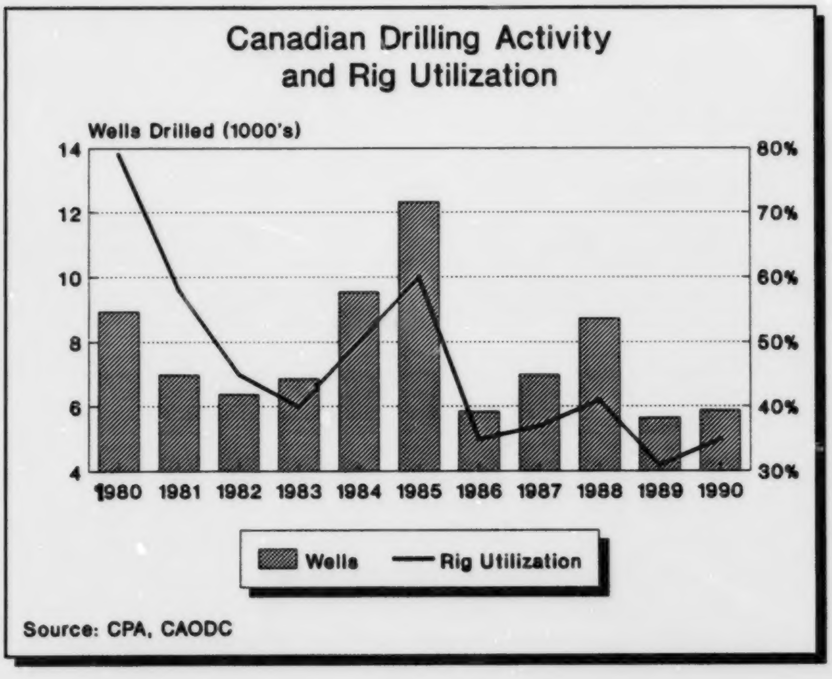
Inflation adjusted annual investment levels since 1986 are 40% below the 1980-85 average



Source: CPA, PowerWest

Figure III.2

Drilling activity and rig utilization have contracted dramatically through the 1980's



Source: CPA, CAODC

Workforce Reductions There have been 3 major rationalizations of corporate staff over the past decade; in 1982 because of the combination of slumping energy prices and the NEP; in

1986 because of the oil price crash; and over the past year because of persistently low prices. In our view, the current round of staff reductions is particularly telling because it represents a fundamental change in the corporate structure of the industry (see below) and as yet shows no signs of abating.

The table below summarizes the major staff reductions over the past year. The statistics were derived from news releases and discussions with company officials and indicate that the companies mentioned in the table have ***eliminated*** approximately ***8,000 to 9,000 jobs since 1989.***

Table III.1

POST 1989 WORKFORCE REDUCTIONS

Announcement	Company	Approximate Number	Comments
April 1989	Mobil	250	Across the organization.
April 1989	Encor	23	Across the organization.
Summer 1989	Gulf	100	All departments.
July 1989	Petro-Canada	800-900	Marketing and other downstream employees.
August 1989	Amoco	510	Split between administration and exploration.
May 1990	Shell	800 (proj)	Downstream.
July 1990	BP	80	Across the organization.
September 1990	Bow Valley	80	Across the organization.
October 1990	Imperial	up to 2,400	Voluntary layoff plan announced.
December 1990	Imperial	600 addit.	Number of voluntary layoffs increased to approximately 3,000.
January 1991	Shell	250-300	Resources.
April 1991	Gulf	250	Administration.
April 1991	Petro-Canada	250-300	Later revised to 230 product staff.
May 1991	Husky	242	Exploration, production, plant, engineering and construction.
May 1991	Amoco	800-900	Across the organization (stated goal is to have 1,500 fewer employees by 1993).
July 1991	Shell	75	Number cut in Information and Computing (stated goal is to have 1,300 fewer employees by end of next year).
Aug 1991	Amoco	500-600	Redeployment, a function of property deal with Encor. Most will be absorbed by other firms related to the transaction.
Aug 1991	Imperial	approx 400	Projected number of downstream to be cut later this year.
September 1991	Home	145	All upstream, primarily in exploration
TOTAL		8,400-8,800	

Source: Reuter Data Base.

Broad rounds of industry lay offs are showing no sign of abating

Nearly all the staff reductions have occurred in the senior and integrated producers. Imperial's 1989 takeover of Texaco and Amoco's 1988 acquisition of Dome, created large-scale duplication of services and thus required a downsizing of redundant personnel. PetroCanada's transition to a public company forced them to focus on the bottom line. Other substantial staff reductions have been implemented by Husky Oil, Gulf Canada, Shell Canada, BP, Mobil, and Bow Valley, for reasons relating primarily to cost pressures and efforts to increase profitability.

We would emphasize that these job reductions do not necessarily imply that the employees were laid off or that the jobs were lost from the industry. Voluntary layoff packages and early retirement inducements are examples of methods that have been utilized by the industry to shed surplus personnel. There has also been some absorption of the most skilled individuals by the junior and intermediate producers and some departure to work internationally. In addition, these has been substantial job loss in the downstream operations of certain companies. Nonetheless, we believe that on the whole there has been a net loss of employment in the sector.

Employment opportunities are minimal for new entrants into the workforce of the upstream sector

One key, but more subtle impact of the general downsizing in the organizational resources of the upstream sector is in the declining employment opportunities for new entrants into the work force. An informal survey of the major producers in the industry has shown with some exception that hiring for the second half of 1991 and 1992 will be strictly on an as needed basis. The majority of the larger firms indicated a cutback of their on-campus recruiting program or termination of this method of hiring. This has affected university enrollment in the disciplines generally seen as critical for the technological advancement of the industry. The University of Calgary has seen enrolment in the disciplines of geology and geophysics fall from about 252 students in 1981 to 73 in 1990.

There has also been tremendous job loss in the drilling sector. Data from Statistics Canada indicates that employment in the contract drilling sector has fallen from over 14,000 in 1985 to less than 7,000 in 1990. There is growing concern that when/if drilling activity increases in the future, there will be a shortage of skilled employees in the drilling and service sectors.

Slower Growth in the Alberta Economy

The importance of the oil & gas industry to the Alberta economy can not be understated.

- In 1990, royalties, land payments and other rentals and fees contributed $2.2 billion or 23% to total provincial government revenues. This source of revenue is critical to a government that ran a $2.1 billion deficit in 1990 and has been running a deficit since 1985.
- Net cash expenditures of the upstream industry (including both capital and operating expenditures and net royalty payments) accounted for 20% of the province's gross domestic product.
- At a total of $7.9 billion, crude oil and natural gas exports accounted for 51% of the province's export revenue in 1990.

There are many positive and high value added "spin-offs" that result from upstream investment activity

- Even though only 7% of the total provincial industrial workforce is directly employed by the oil & gas industry, thousands of other jobs in manufacturing, construction, transportation, finance and the service sectors rely on the expenditures of the oil & gas industry.

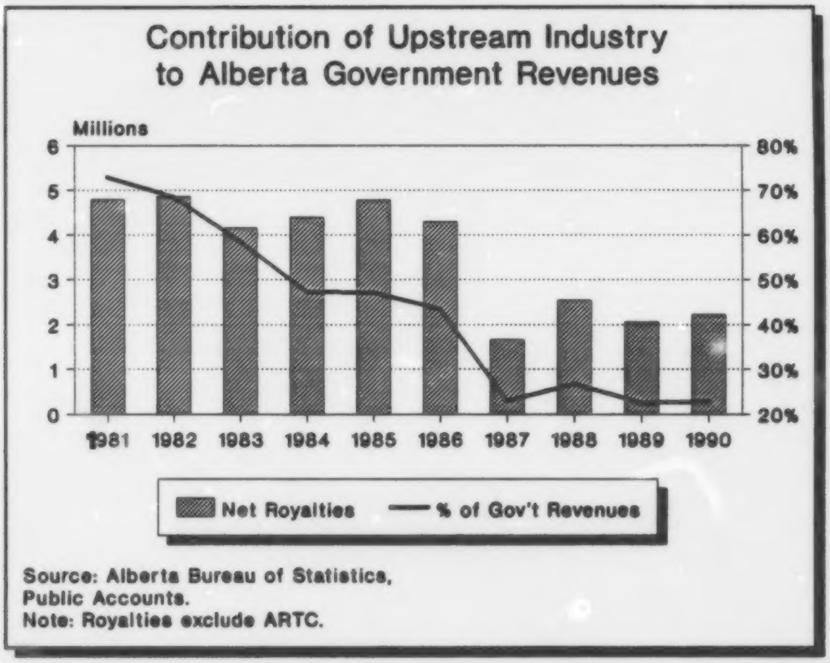
- During the past year, $108 million was spent on 'in-house' research and development in Alberta by the large industry firms. This money provided highly skilled value-added employment as well as technical advances for more efficient production techniques.

- The vertical integration of the oil and gas industry within Alberta provides value-added employment and tax revenue at the many different stages of the production, refining and distribution chain.

Importantly, while still critical to the health of the Alberta economy, the contribution of the upstream sector has declined significantly since 1980 in tandem with the deterioration in the sector's profitability.

- Revenue from royalties and land bonuses provided the government with an average of over $4.6 billion per year between 1981 and 1986 (net of ARTC), about 55% of the total government revenue over this period. The government's take has fallen dramatically since 1987, to an average of $2.1 billion or slightly less than 25% of total revenue.

Figure III.3

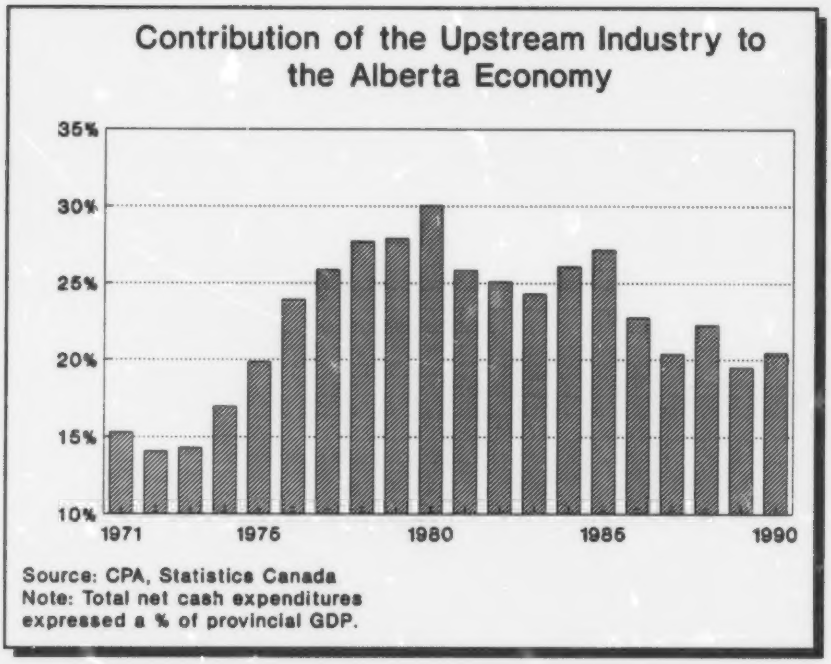


Source: Alberta Bureau of Statistics,
Public Accounts.
Note: Royalties exclude ARTC.

- The total expenditures of the upstream industry (capital, operating and royalty expenses) accounted for 30% of total provincial GDP back in the late 1970's. Today it accounts for only 20% of the provincial GDP.

Figure III.4

The contribution of the upstream industry to the Alberta economy has diminished through the 1980's



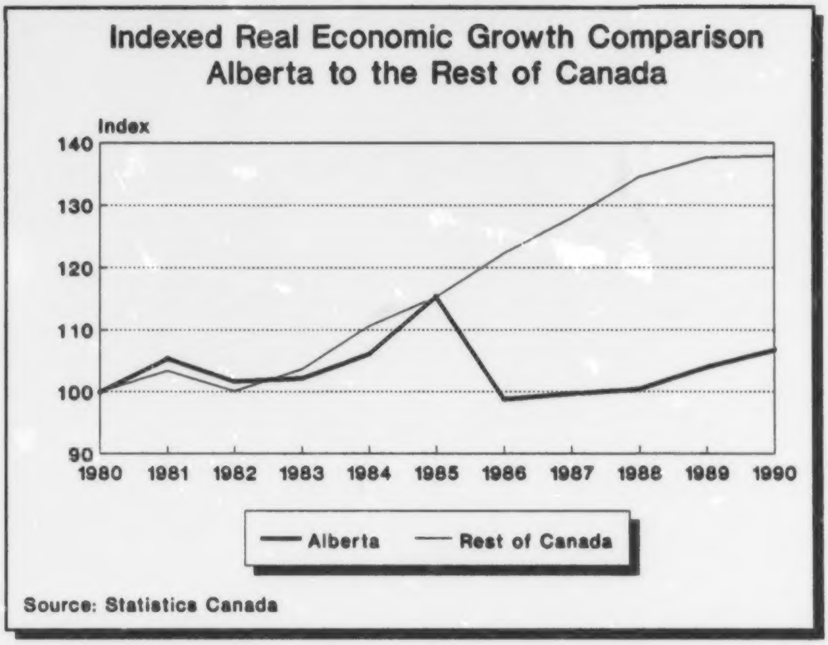
Source: CPA, Statistics Canada
Note: Total net cash expenditures expressed a % of provincial GDP.

This reduced contribution from the upstream industry since the early 1980's has had a substantial impact on the Alberta economy.

- Alberta's economy significantly underperformed the Canadian economy between 1980 and 1990. Over this period, the Alberta economy expanded by less than 10% in real terms. In sharp contrast, the rest of the Canadian economy grew by nearly 40%.
- The provincial government's revenue sources have been essentially flat since 1986. There was actually a sharp drop in 1987 due to reduced royalties that was essentially replaced by higher income and "sin" taxes and income from the Heritage Trust fund. However, over this same period government spending has continued to rise by about 5% per year. The consequence has been the emergence of a persistent annual deficit that has averaged about $2 billion per year since 1987.

Figure III.5

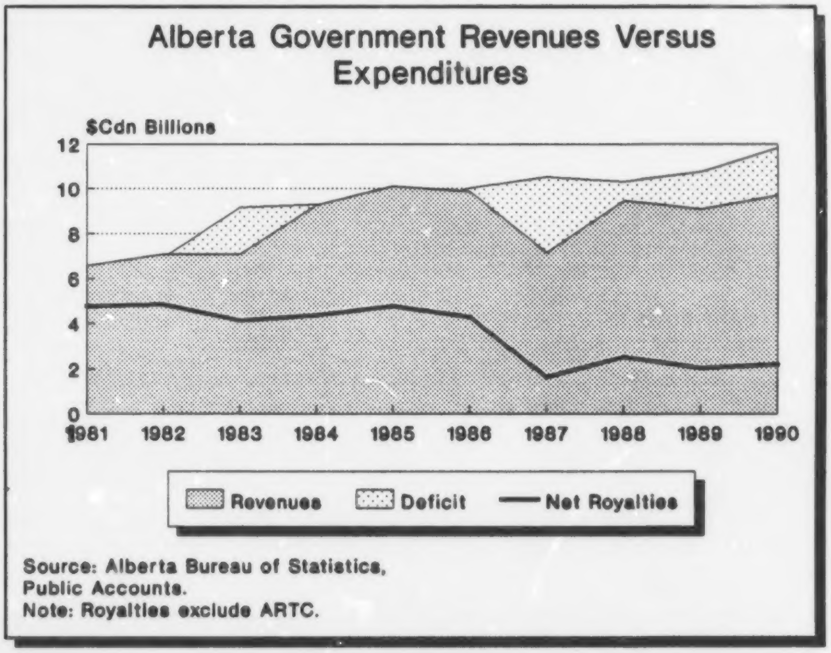
Over past decade Alberta economy grew 10% in real terms versus 40% for Canadian economy



Source: Statistics Canada

Figure III.6

Government spending has not yet adjusted to the reality of "low" royalties



Source: Alberta Bureau of Statistics, Public Accounts.
Note: Royalties exclude ARTC.

RATIONALIZATION AND RESTRUCTURING

The inalterable reality of poor profitability, poor share price performance and the growing realization that there is no guarantee of higher prices in the future has forced the Canadian upstream industry to consider profound changes in the way it does business. The process, which we have termed "Rationalization and Restructuring", began in earnest in 1986 following the collapse in oil prices, continued through the late 1980's and remains a strong force shaping the future of the Canadian oil and gas industry.

Objectives

The principle objectives of rationalization are fundamental and absolutely critical to maintaining the longer-term health and viability of the upstream industry.

1. *Increase Profitability from Existing Assets*

- Returns on existing assets have been unacceptably low since 1980 as was clearly demonstrated in Section I. As companies have no influence on prices, they must focus internally on the factors that they can control, most notably costs and productivity. Quite simply, the industry must become more effective in managing its assets, and the costs of doing so must be reduced or at a minimum cost increases must be contained.

2. *Ensure Adequate Rates of Return on New Investments*

- Given that returns on existing assets are so poor, the industry can ill afford the dead weight of possibly unprofitable new investments. Every project must be carefully scrutinized and properly risked before acceptance to ensure that acceptable rates of return will be generated. Marginal projects must be abandoned or deferred until business conditions warrant.

Achieving these Objectives

Most companies now have well-defined strategies and plans to achieve these objectives. We discuss the major elements of these strategies below.

1. *Restructure Corporate Organization*

- *Shed Redundant Staff*. Reductions in operating and overhead costs require that manpower be downsized and employed more efficiently.

- *Create Value Centres*. Certain of the large senior and major companies are establishing internal business centres that are to be run on a stand alone basis with the ultimate goal of meeting entity specific targets and objectives.

- *Flatten Management Structure*. Many companies are shifting away from the traditional corporate hierarchical structure, eliminating layers of middle management and transferring more responsibility down in the organization. The new corporate organization will have greater flexibility and the ability to make quicker decisions.

2. *Optimize Asset Portfolio's*

- Companies have identified cost reductions and productivity improvements that can be achieved by focusing more on "core" assets--those that make meaningful contributions to the earnings of the corporation. "Non-core" assets--those that do not make a significant contribution to the bottom line--are being targeted for divestment. The intent is to more effectively manage the core assets and to eliminate the costs of administering and managing less important assets.

There is now a significant opportunity to expand through acquisition rather than exploration

3. *Achieve Growth Through Acquisitions Versus Exploration & Development*

- The disposition of assets by many of the major companies has created an opportunity for other companies to achieve their growth objectives through acquisition rather than through the exploration and development of new reserves.

4. *Corporate Consolidation*

- Since the 1986 price crash, there has been unprecedented volume of corporate activity. Nearly all financially distressed firms have found new owners. As well most of the sizable independent companies acquired dominant shareholders. Many existing dominant shareholders though are looking to sell, often because of their own consolidation plans. In addition, there are incentives for consolidation among the junior companies to improve economics of scale, and to gain sufficient size to be able to withstand exploration failures. This trend is a natural consequence of low commodity prices and poor profitability and will likely continue well into the 1990's.

5. *High Grade Investment Opportunities*

- With the decrease in the amount of cash flow and outside sources of capital, and the difficulty in achieving acceptable rate of return in the current pricing environment, the industry is generally pursuing only its best investment projects.

6. *Increase International Exposure*

- Given the diminishing returns in the WCSB, many Canadian oil and gas companies are looking to increase their exposure in international areas where prospective returns are much higher.

7. *More Creativity in Search and Application of New Technologies*

The development and application of new technologies may be the key to lowering, or at least containing cost pressures in the WCSB

- Enhanced oil recovery technology has been implemented on most of the major fields but further cost reductions (or higher prices) are required to make the technology economic in the numerous smaller fields now approaching the end of their economic life.
- 3D seismic technology is increasingly being used to reduce dry hole costs and optimize development programs.
- Horizontal drilling, which has the potential to dramatically improve productivity and recovery rates in certain formations, is gaining acceptance.

- Cost effective field upgrading could dramatically improve the overall economics of heavy oil production, a substantial resource that has significant longer-term growth potential.

Implications of the Rationalization and Restructuring Process

We see two very broad but powerful consequences arising from the Rationalization and Restructuring process. Both point to a diminishing industry, an industry that is downsizing in order to survive and satisfy investor return requirements.

1. *Reduced and Redirected Capital Resources*

- The general contraction in capital spending since 1986 is largely the result of the drop in industry cash flows. However, several other factors have influenced spending levels and we feel these factors will lead to generally lower re-investment in the future, including:
  - *Investment economics in the WCSB are relatively poor in the current price environment (see Section IV).*
  - Projects will have to satisfy *higher hurdle rates.*
  - There will be a move away from 'hockey stick' shaped pricing forecasts and towards more *"hard headed" view of future prices.*
  - There will be an increasing *focus on core areas* to generate exploration and development opportunities.
  - The shift to *international* areas is likely to gain momentum.
  - The major companies have, and will continue to *spend considerably less than* internally generated *cash flow* on conventional exploration and development activities.
  - Recently and likely over the next few years, the record volume of *assets* and *corporations for sale* will *redirect expenditures* away *from exploration* and development.
  - Companies will *avoid exposure to high cost projects.* Although Hibernia is still going ahead as planned, many companies are attempting to sell their interest in frontier and megaprojects, or are taking write-offs and essentially abandoning existing development plans. The OSLO development has been delayed once again and will not likely be a factor over the next decade. Bitumen and heavy oil economics are also poor at this time because of high quality differentials.

Lower investment and employment are inevitable consequences of persistent poor profitability

2. *Reduced and Redirected Organizational Resources*

- It is difficult to see employment in the upstream sector increasing significantly in the future. This is an unfortunate but harsh consequence of poor profitability. Although attrition will create some opportunities, new entrants into Alberta's workforce are, more than ever, going to have to look to other sectors of the economy for employment opportunities.

Poor profitability has a profoundly negative impact on all stakeholders in the industry

Our main conclusion is that the *low level of profitability for the upstream oil and gas industry has had a profoundly negative impact on all stakeholders in the industry: shareholders and investors (generally), the people who work within or depend on the industry for their livelihoods, and on the major producing province of Alberta. The link between profitability and industry growth, employment levels and the industry's contribution to the general economy is undeniable. Low levels of profitability through the 1980's has forced the industry to downsize, reducing its capacity to employ people and contributing to a reluctance to commit additional capital to the sector.* While a detailed analysis of this emerging trend to the Alberta economy is beyond the scope of this report, we believe it raises some extremely important and sobering questions.

SECTION IV — CANADIAN UPSTREAM INDUSTRY OUTLOOK – PERSPECTIVES ON FUTURE PROFITABILITY

MAJOR CONCLUSIONS

1. There is an understandable growing pessimism in both the producing and investment communities about the medium to longer-term outlook for oil and gas prices. For the past five years, recovery in oil and gas prices has remained elusive. It seems as if the always expected recovery in prices has become a moving target continuously shifting further into the future. Increasingly, business executives and investors have begun to question the reasonableness of rising real price scenarios.

2. Given the tremendous uncertainty with respect to future prices, we believe the outlook for the Canadian upstream industry must be examined under a fairly wide range of future prices. We have chosen to adapt the upper and lower bounds of an independent survey of 17 Canadian petroleum consultants' price forecasts (over the 1991-95 period). The low price forecast is reflective of a WTI price track that falls just below $US 20/B in 1992 and rises slowly to $US 23/B by 1995. In the high price forecast, WTI prices increase substantially in every year, rising from just under $22/B in 1991 to $28.50/B by 1995. For natural gas, the low forecast has prices falling modestly over the next two years only barely exceeding 1990 levels by 1995. Under the optimistic forecast, prices approximately double between 1991 and 1995, from about $1.40/Mcf to $2.70/Mcf. The wide range of gas price forecasts reflects the disparate opinions that exist with respect to the future of natural gas.

3. *It is now virtually certain that upstream revenues will fall sharply in 1991 under the weight of depressed gas prices, record high light/heavy differentials and the continued strength of the Canadian dollar.* Both price scenarios indicate that gross revenues should be about $18 billion, slightly below 1989 levels. Under the low price scenario, revenues continue to slide into 1992 and remain below 1991 levels in 1993. This result stems largely from a further weakening in natural gas prices combined with flat oil prices and declining conventional light and medium oil production. Although recovery in prices pushes revenues steadily up thereafter, they still do not reach 1990 levels by 1995. Revenues rise sharply after 1991 under the high price scenario. These high prices are sufficient to generate all time record high revenues of just under $30 billion by 1995.

4. *Containing future operating costs is one of the major challenges the industry faces in the years ahead.* It is very possible that the continued aging of the older fields and lower productivity, higher cost additions could result in real growth in costs. The industry as a whole, however, is very cognizant of this possibility. Much of the current rationalization and restructuring now underway in the sector is focused on dealing with this problem. These efforts will likely contain further increases in costs but may not be sufficient to reverse this intractable trend. Considering all factors, we believe that operating costs on a BOE basis will escalate with inflation (5% per year) over the forecast horizon.

5. *The Canadian upstream sector as a whole is very vulnerable to a scenario of flat prices due to high and increasing operating costs and a fairly price insensitive royalty regime.* This vulnerability was clearly demonstrated in 1986 and again in 1988 when cash flows fell precipitously in response to lower prices. A similar trend is expected in 1991 based on prices and corporate results through the first half of the year. Our projections indicate that the internally generated cash flow in the upstream sector should fall by 25% this year, to about $6.1 billion. The prospects for cash flow under the low price scenario are extremely poor. Higher interest expenses, continued growth in operating costs, production declines and lower gas prices combine to drag 1992 cash flows down to 1986 levels of just over $5 billion. Some

recovery in cash flows result in the 1993-95 period due to improvement in prices, but the total remains well below 1990 levels throughout the forecast horizon.

6. *Upstream earnings are even more leveraged than cash flows to changes in oil and gas prices because of the high and fixed nature of D&D charges (barring writedowns in the value of the assets being depleted).* Again, the key perspective is the vulnerability of the sector to lower prices. Net earnings in 1991 are projected to fall to a nominal $200 million, from $1.8 billion in 1991. Under the low price scenario, net losses are incurred through the entire 1992-1995 period. The substantial growth in earnings projected under the high price scenario stands in sharp contrast, increasing steadily every year to nearly $2.7 billion in 1995.

7. We have evaluated the economics of exploring and developing oil and gas reserves in Alberta under these two price scenarios and under various finding and development (F&D) costs. The principal conclusions drawn from this analysis are as follows:

    - It will be very difficult for the industry as a whole to generate acceptable rates of return on future conventional oil exploration, even under the high price scenario.
    - Investment economics for natural gas are very poor under the low price scenario based on full cycle economics and average F&D costs over the past five years.
    - Relatively poor investment economics for both oil and gas will constrain future capital spending.

8. *Investment in the conventional areas is likely to remain below internally generated cash flow for the foreseeable future.* Based on drilling activity to date and estimated spending on the Caroline project, investment in Western Canada in 1991 is expected to be in the order of $6.4 billion, up over 6% from last year. Under the low price scenario, investment in conventional areas begins to contract due to the combination of lower cash flows and poor investment economics, falling to an average of about $4.5 billion per year between 1993 and 1995. These levels would be a post-1980 low for the industry. Our projections of capital spending, combined with reasonable expectations for future finding rates, indicate that Western Canadian oil and gas reserves will shrink over the forecast horizon under both price scenarios.

9. *Our key general conclusion is that we see very little scope for the industry to return to profitability over the first half of the 1990's. In the low price scenario, the Canadian upstream sector would incur earnings losses and essentially negligible ROCE's over the entire forecast horizon. This again underscores the vulnerability of the Canadian upstream industry to a future where there is only minimal growth in nominal oil and gas prices. Under the high price scenario, ROCE's remain below 4% through 1994 and grow to 6% in 1995, still well below the industry's historical cost of capital.*

10. We have examined the industry outlook under a wide array of alternative scenarios to establish a better understanding of the conditions that might restore acceptable levels of profitability over the next five years. Key conclusions are as follows:

    - *The level of prices required to generate acceptable profitability over the next five years are well beyond even the most aggressive forecasts.*
    - *If the industry is able to hold operating costs constant over the forecast horizon, returns still remain well below acceptable levels through the forecast horizon.*
    - *If the industry holds operating costs constant and dramatically scales back re-investment levels, then profitability starts to approach acceptable levels in the mid-1990's. However, this is only in the aggressive high price scenario. If the low price scenario prevails, even draconian cost containment and investment curtailment plans will not restore acceptable levels of profitability.*

SECTION IV

CANADIAN UPSTREAM INDUSTRY OUTLOOK – PERSPECTIVES ON FUTURE PROFITABILITY

INTRODUCTION

The evidence presented in the previous three chapters shows undeniably that the upstream sector of the Canadian oil and gas industry has been in a severe downturn for the past five years. This section of the report attempts to look past these depressing conditions to gain a reasoned and well-balanced perspective on the medium-term prospects for the sector.

The section opens with a brief discussion of the general market fundamentals for oil and gas and develops the rationale for the use of two price scenarios employed in all subsequent analysis. These price scenarios bracket the range of current industry views toward the commodities. With this background in place, the outlook for the upstream sector is examined, focusing firstly on production volumes and on the key items relating to revenue and income. The components of capital are then assessed. Capital expenditures and investment economics are considered and capital employed is forecast under the two price scenarios. The implications of the financial projections are drawn as relating to industry profitability, industry activity levels and reserve trends. The section closes with an assessment of profitability under certain sensitivities, notably certain higher price scenarios and lower cost and capital spending scenarios.

PRICE EXPECTATIONS

There is an understandable growing pessimism in both the producing and investment communities about the medium to longer-term outlook for oil and gas prices. For the past five years, recovery in oil and gas prices has remained elusive. It seems as if the always expected recovery in prices has become a moving target continuously shifting further into the future. Increasingly, business executives and investors have begun to question the reasonableness of rising real price scenarios.

Based on an ongoing and close monitoring of both world oil and North American natural gas markets, PowerWest believes there are several compelling reasons to expect that future oil and gas prices will be higher than today's levels after adjusting for inflation. We also feel, however, that there are many factors which will contain any significant upward pressure on prices. Also, as always, there are unforecastable events and developments which will have a considerable impact on future prices. The table provided below contrasts the positive and negative market fundamentals for both oil and gas, and highlights the major uncertainties in the outlook for each commodity.

Table IV.1

Key trend for oil is the emerging dominance of OPEC, in particular Saudi Arabia

Supply outlook is the major uncertainty for natural gas

COMMODITY MARKET FUNDAMENTALS

Crude Oil

Positives

- Rising demand in developing world and eventually Eastern Europe
- Declining production in the U.S. and U.S.S.R.
- Fairly flat production elsewhere outside of OPEC
- Growing call on OPEC
- Impending need for OPEC to add substantial production capacity
- Reliance of OPEC members on oil revenues for foreign exchange
- Concentration of power within OPEC among the six producers that possess excess capacity, particularly Saudi Arabia

Negatives

- Fairly flat demand in OECD countries
- Impending environmental initiatives
- OPEC's dramatic cost advantages in both exploration and production
- OPEC's very substantial reserve base and it's enormous latent productive capability
- Heavy Oil
  - Continued lightening in demand
  - Tighter product specifications
  - Growing supplies
  - Shortage of upgrading capability

Major Uncertainties

- Continued improvement of supply side technologies
- Large discoveries outside of OPEC
- Nature and impact of impending environmental initiatives
- Political volatility in the Middle East
- Dominant OPEC producers support for rising prices in real terms over long-term

Natural Gas

Positives

- Demand on firm growth trend
- Positive fundamentals for gas use in electricity generation
- Environmentally benign fuel
- Drilling activity falling
- Productive capacity in decline
- Pipeline expansion imminent
- Higher prices necessary to stimulate levels of drilling required to meet expected future demand growth

Negatives

- Industry structure:
  - Very fragmented producing sector
  - Deregulated producing sector selling through regulated pipelines to regulated buyers
- Short-term shortage of ex-Alberta pipeline capacity
- Current excess productive capacity in Canada
- Emergence of coal seam gas in U.S.
- Regulatory intervention in California
- Potential overbuild of pipeline capacity into California

Major Uncertainties

- Supply side response to higher prices, particularly in the U.S.
- Weather
- Technological advances:
  - In gas supply
  - In clean coal technology
- Impact of environmental initiatives
- Penetration into transportation market

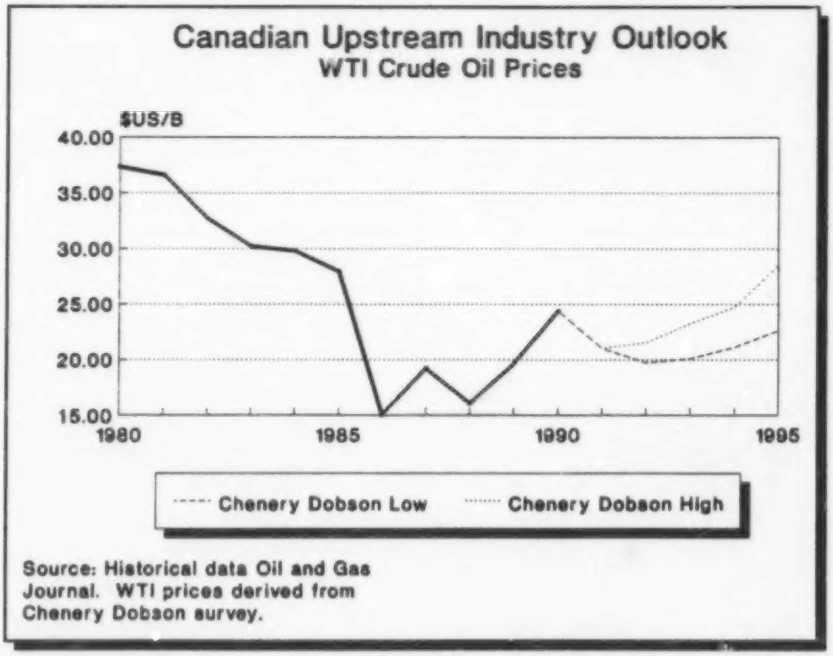
As the above summaries indicate, higher real, and possibly even nominal prices, for both oil and gas are by no means guaranteed, particularly over the medium-term. To address the extreme uncertainty in future prices, we believe the outlook for the upstream sector must be examined under a broad range of "reasonable" prices.

Relying on survey of 17 consultants' price forecasts to establish reasonable upper and lower bounds

Rather than rely on any single organization for this "reasonable" range, we have chosen to adapt the upper and lower bounds of the most recent Chenery Dobson (CD) survey of Canadian petroleum consultants' price forecasts (over the 1991-95 period). The survey includes over seventeen consulting firms active in the evaluation of Canadian oil and gas properties. The forecasts are those that were being used by these firms as at July 1, 1991.

The oil prices provided by the consultants are for the light sweet Swan Hills crude stream at Edmonton. These prices require an upward adjustment of about $Cdn 0.50/B to be consistent with the widely quoted Edmonton light sweet reference price posted by all the major refiners. As the WTI prices and exchange rate assumptions underlying these prices are unknown, we have used our crude pricing model to back out the implied WTI price assuming an exchange rate of $0.83 US/Cdn after 1991 ($0.86 US/Cdn in 1991) as we believe most forecasters are anticipating some weakness in the Canadian dollar from current levels. The implicit WTI prices are portrayed in the graph provided below. The low price forecast is reflective of a WTI price track that falls just below $US 20/B in 1992 and rises slowly to $US 23/B by 1995. Under the high price forecast, WTI prices increase substantially in every year, from just under $22/B in 1991 to $28.50/B by 1995.

Figure. IV.1



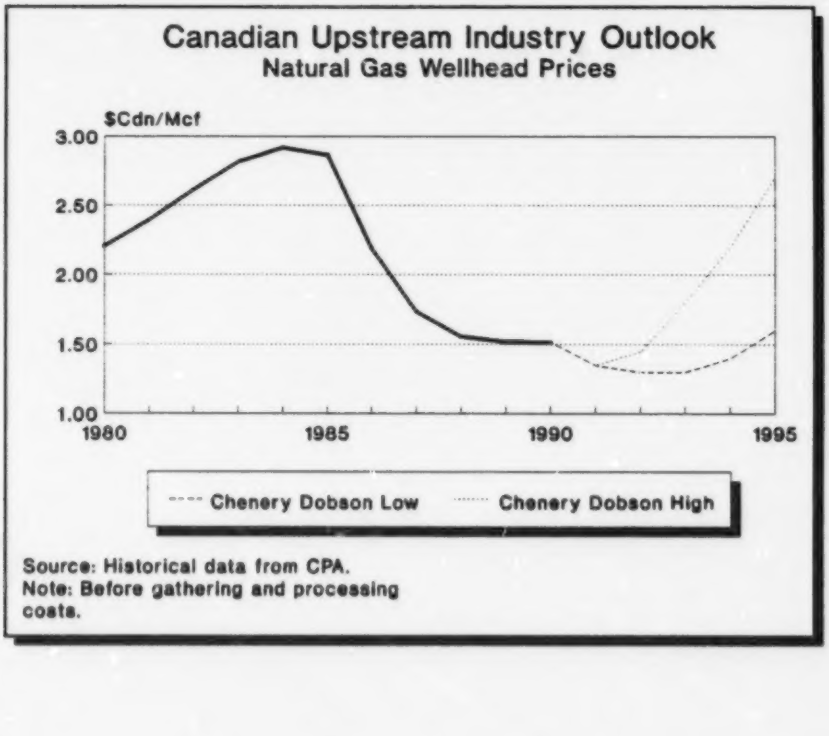
Source: Historical data Oil and Gas Journal. WTI prices derived from Chenery Dobson survey.

Given that conventional heavy and bitumen output comprise a significant and growing portion of total Canadian liquids production (nearly 25% in 1991), quality differentials are an important input into the overall analysis. We have made projections of the light/heavy and light/bitumen differentials based on recent trends. Quite generally, differentials are assumed to narrow slightly in 1992 and then increase at a rate somewhat less than inflation. These differentials are used to estimate a set of prices for these products that are consistent with the light price forecasts and are held constant across both scenarios. A detailed breakdown of the pricing assumptions for all the upstream products is provided in Appendix VI.

Wide range in gas price forecasts reflects the extreme uncertainty in future prices

The gas prices provided by the consultants in the CD survey are for the average Western Gas Marketing Limited (WGML) price with TOPGAS. Our experience is that this price is a fairly accurate reflection of the average Alberta wellhead price. While gas prices in B.C. tend to be slightly lower, this is offset by Saskatchewan prices which are generally higher. We are therefore comfortable using the average WGML price as a proxy for the average Canadian gas wellhead price. The two different price forecasts are compared in the graph below. The wide range throughout the forecast horizon is reflective of the disparate opinions that exist with respect to the future of natural gas. The low forecast has prices falling modestly over the next two years only barely exceeding 1990 levels by 1995. Under the optimistic forecast, prices approximately double between 1991 and 1995 from about $1.40/Mcf to $2.70/Mcf.

Figure IV.2



Source: Historical data from CPA.
Note: Before gathering and processing costs.

INDUSTRY OUTLOOK

Production

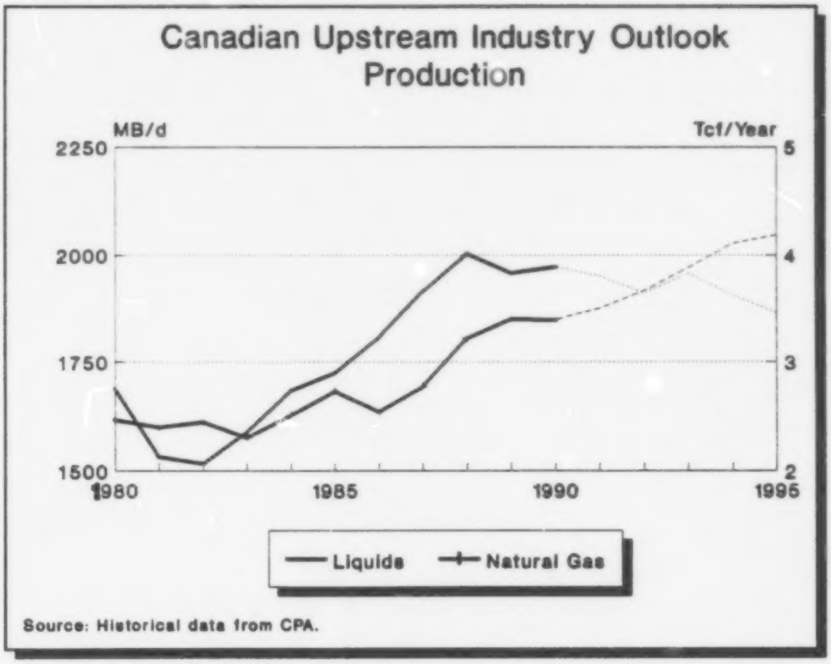
Conventional light and heavy oil production from current reserves is assumed to decline at 10% per year. Production from new reserve additions is dependent on the level of capital investment (determined by the level of oil directed drilling activity and the finding rate) and is assumed to come on stream immediately with a reserve life of 10 years.

Conventional light oil production is in long-term decline

Synthetic production is held relatively constant over the forecast horizon. Both the Syncrude and Suncor plants are at maximum capacity barring major capital investment in debottlenecking programs. The proposed OSLO facility will not be a factor over the next five years and may not even be on stream at the turn of the century. Bitumen production is expected to increase by 20 MB/d over current levels of 135 MB/d once Phases 7 and 8 of Imperial Oil's Cold Lake project are brought on stream.

Pentanes plus and natural gas liquids (NGL) production are projected to increase substantially in 1993 when Shell's Caroline field is expected to begin production.

Figure IV.3



Source: Historical data from CPA.

Gas production set to grow significantly over next five years

Gas production is assumed to be demand driven. Domestic demand is projected to grow at about 2% per year over the next decade and exports to the U.S. rise to about 2 Tcf per year by 1995 and then remain fairly flat thereafter. This suggests that 1990 sales volumes of about 3.4 Tcf should rise to 4.2 Tcf by 1995, implying average growth of just under 5% per year. We believe it is reasonable to assume gas exports remain constant across both price scenario's as this growth is based on the contracted volumes underpinning new pipeline capacity that can be expected with a high degree of certainty. Domestic demand would be responsive to prices but the potential variance would not materially affect the results presented below.

Gross Revenues

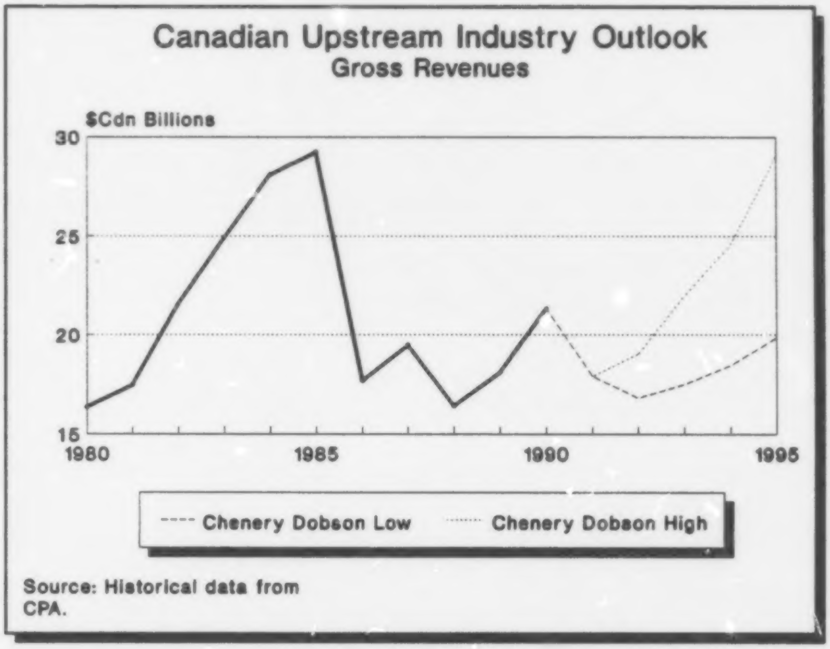
It is now virtually certain that upstream revenues will fall sharply in 1991 under the weight of depressed gas prices, record high light/heavy differentials and the continued strength of the Canadian dollar. Both price scenarios indicate that gross revenues should be about $18 billion, 16% below 1990 levels and slightly below 1989.

Under the low price scenario, revenues continue to slide into 1992 and remain below 1991 levels in 1993. This result stems largely from a further weakening in natural gas prices combined with flat oil prices and declining conventional output. Although recovery in prices pushes revenues steadily up thereafter, they still do not reach 1990 levels through the five year forecast period.

Revenues rise sharply after 1991 under the high price scenario. These high prices are sufficient to generate all-time record high revenues of just under $30 billion by 1995.

Figure IV.4

Industry revenues do not recover to 1990 levels under the low price scenario



Source: Historical data from CPA.

Royalties

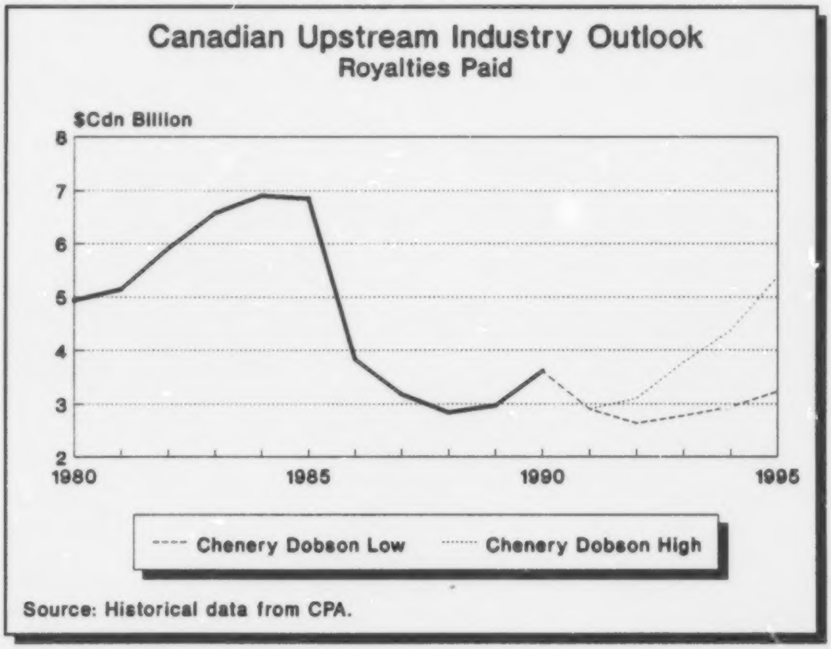
Royalties are a major cash expense of the sector. Although the royalty formulae in all provinces are price sensitive, because they are based on revenue rather than income a substantial bill must still be paid even though business conditions may be severely depressed. This will certainly be the case in 1991 when royalties paid are estimated to be in the order of $2.9 billion, just over 16% of gross revenues, and at a time when industry income is effectively nil.

Royalties are and will continue to be a major cash expense to the industry

Under the low price scenario, royalties paid are expected to be fairly flat, remaining below $3 billion until 1995. This type of situation could pose a serious problem to the Alberta government which receives the bulk of these revenues. The province has not yet been able to adjust to the lower royalties it has been receiving post-1985. Unless other revenue sources are found or spending growth is curtailed, the current annual deficit of approximately $2 billion (which occurred despite the relatively high royalties received in 1990 because of the Gulf Crisis) could balloon to much higher levels.

Under the high price scenario, royalties paid are projected to nearly double between 1991 and 1995, to $5.4 billion, but still remain well below the peak takes the provincial governments enjoyed during the mid 1980's.

Figure IV.5



Source: Historical data from CPA.

Operating Costs

As discussed earlier in the report, the increase in operating costs over the past few years in the face of falling revenues is a major contributing factor to the current poor profitability of the upstream sector. It appears that the underlying pressure on costs is largely due to the inexorable aging of the largest oil and gas fields, and the relatively low productivity of recent discoveries.

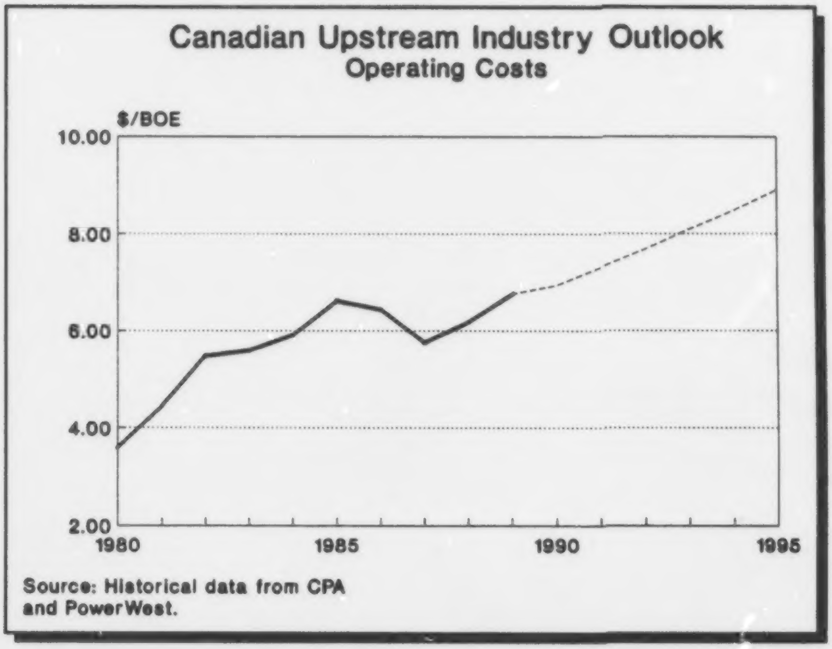
High and increasing operating costs are a major contributor to low profitability

Containing future operating costs is one of the major challenges the industry faces in the years ahead. It is very possible that the continued aging of the older fields and lower productivity, higher cost additions could result in real growth in costs. The industry as a whole, however, is very cognizant of this possibility. As discussed in Section III, much of the current rationalization and restructuring now underway in the sector is focused on dealing with this problem. These efforts will likely contain further increases in costs but may not be sufficient to reverse this intractable trend.

Considering all factors, we believe that the steps industry is now taking will likely prevent any real increases in operating costs (including general and administrative expenses). Our general assumption is that industry average operating costs on a BOE basis will escalate with inflation (5% per year) over the forecast horizon. This is approximately the average rate of increase observed over the past three years and is widely used by independent engineers in preparing valuations of oil and gas properties.

Based on this assumption, operating costs still remain the largest expense that the industry faces over the forecast horizon. Total operating costs should exceed $7 billion and account for roughly 40% of gross revenues in 1991. Under the low price scenario operating costs grow to 45% of gross revenues by 1995. This ominous trend underscores the urgency and importance of the steps now being taken to contain operating costs. The problem is obviously not as acute under the high price scenario where operating costs fall to just over 30% of revenues by 1995.

Figure IV.6


Canadian Upstream Industry Outlook
Operating Costs

Source: Historical data from CPA and PowerWest.

Containing future operating costs is a major challenge for the upstream industry

Interest Expense

Debt is used to fund any excess of capital spending and dividends over internally generated cash flow and equity injections. Debt is paid down if the reverse is true and there is a surplus of funds (see Appendix VI for a summary of the assumptions concerning dividends and equity injections).

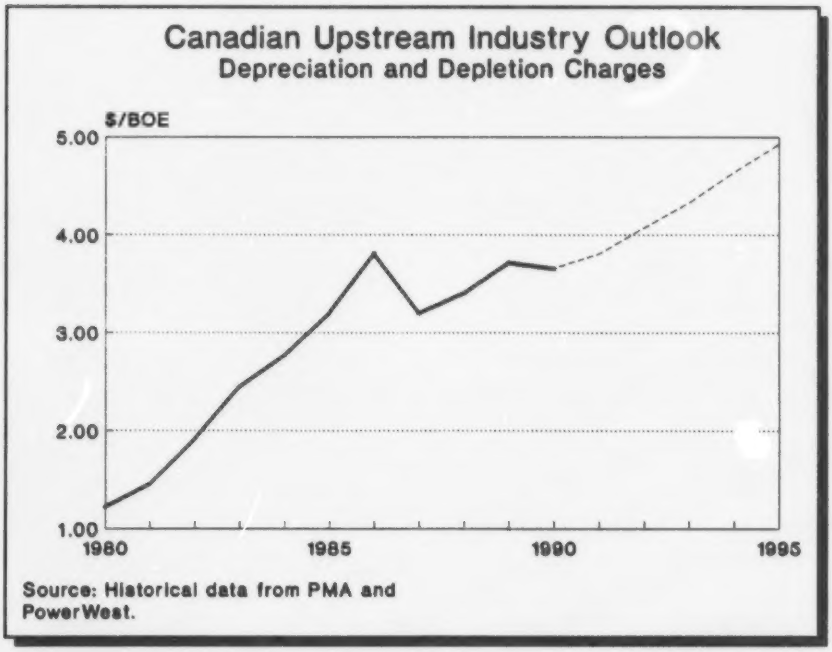
Based on the major projects which are in progress at this point in time and our projected investment in conventional areas, total investment levels are likely to exceed internally generated cash flows over the next few years under both price scenarios (see below). We believe that most of this shortfall will have to be funded by debt given current equity market conditions. As a result, the sector as a whole is likely to face higher levels of debt and, barring a substantial reduction in interest rates, higher interest expense over the forecast horizon. Alternatively, capital spending in this scenario may be lower than forecast, with consequent wide ranging effects on both income and capital components for the sector. Based on the investment projections in our existing scenarios, the expected increases in interest expense are relatively modest, held back by expected lower interest rates. As the discussion on cash flow and earnings below clearly illustrates, however, the sector as a whole can ill afford any increase in cash expenses under the low price scenario.

Depreciation and Depletion Expenses

The upstream sector faces the prospect of growing depreciation and depletion (D&D) charges through the 1990's. D&D is currently the second largest expense incurred by the sector (albeit a non-cash expense), and the high capital expenditures in the 1980's and relatively poor finding and development costs have created a certain momentum that will be very difficult to halt unless future spending is severely curtailed. We project future D&D expenses employing the units of production approach that is used by the companies operating in the sector. The calculated amounts through 1995 are relatively insensitive to the level of spending over this period and are expected to increase from a total of $3.7 billion in 1990 to $4.8 billion under the low price scenario, and to just over $5 billion under the high price scenario. D&D expenses per BOE produced increase from $3.66 in 1990 to nearly $5.00/B in 1995.

Figure IV.7

Depreciation and depletion charges are on a firm rising trend

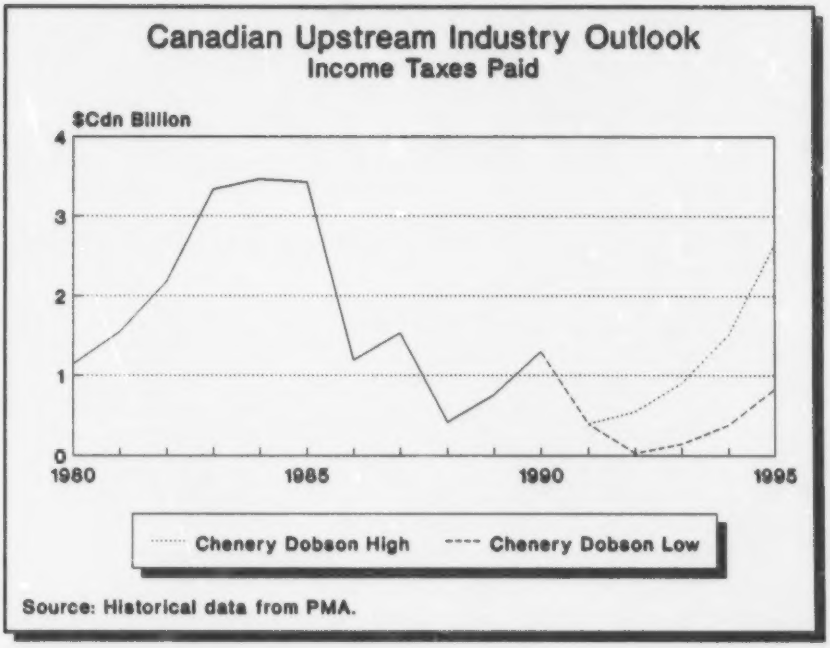


Source: Historical data from PMA and PowerWest.

Income Taxes

Estimating the future tax expense of the industry is extremely complex, primarily because of the widely disparate tax exposure of the myriad of companies operating in the sector. Our approach to calculating current taxes is based on the actual tax calculation. Expense deductions are calculated from the pools that are available to the industry (provided by the PMA) but are adjusted to reflect historical usage under similar financial conditions. This approach captures the fact that a large portion of these pools are held by companies that cannot efficiently use them.

Figure IV.8



Source: Historical data from PMA.

Deferred income taxes have also been a periodic major (non-cash) expense for the upstream industry. Quite generally, the total taxes deferred by the sector have been relatively low when business conditions are poor because available tax pools can not be efficiently utilized. When the cash flows have been at relatively high levels, deferred taxes were very substantial (over $1.7 billion in 1985) as companies with large tax pools are able to more effectively employ them. Our treatment of taxes and projections of deferred taxes embody these fundamentals.

Cash Flow

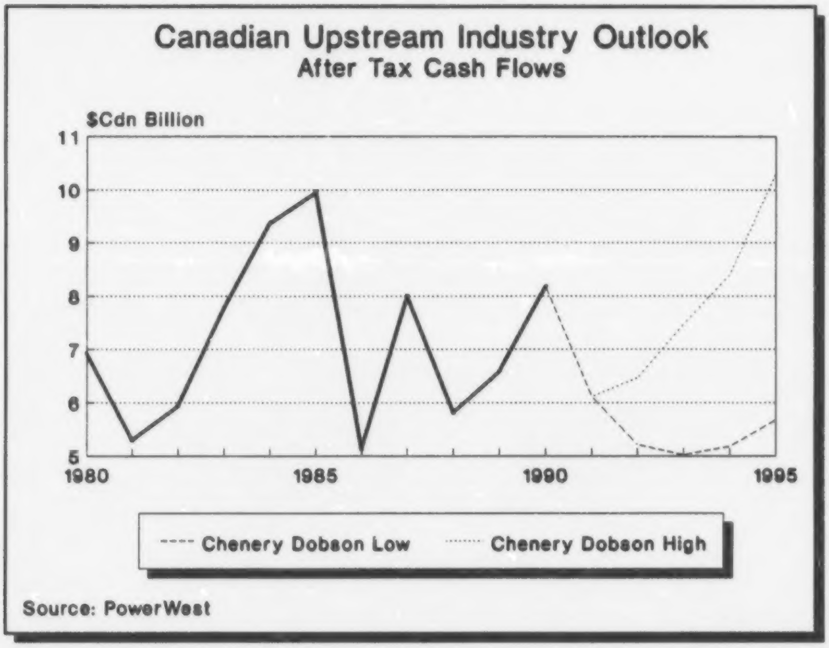
The Canadian upstream sector as a whole is very vulnerable to a scenario of flat prices due to high and increasing operating costs and a fairly price insensitive royalty regime. This vulnerability was clearly demonstrated in 1986 and again in 1988 when cash flows fell precipitously in response to lower prices. A similar trend is expected in 1991 based on prices and corporate results through the first half of the year. Our projections indicate that internally generated cash flow in the upstream sector should fall by 25% this year, to about $6.1 billion.

Industry cash flows remain below 1988 levels through 1995 under the low price scenario

The prospects for cash flow under the low price scenario are extremely poor. Higher interest expenses, continued growth in operating costs, production declines and lower gas prices combine to drag 1992 cash flows down to 1986 levels of just over $5 billion. Some recovery in cash flows result in the 1993-95 period due to improvement in prices, but the total remains below 1988 levels throughout the forecast horizon.

While the upstream sector is extremely vulnerable under a scenario of essentially flat prices, it is also highly levered to price recovery. Under the high price scenario, cash flows grow rapidly after 1991 and are projected to exceed 1985's record levels of $10 billion by 1995.

Figure IV.9



Source: PowerWest

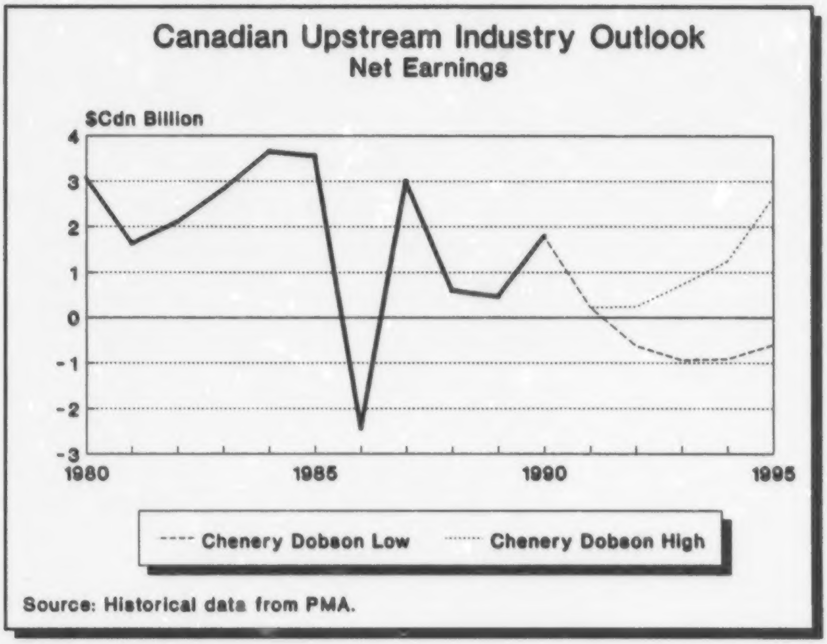
Earnings

While cash flow has traditionally been the barometer used to measure the financial health of the upstream sector, in isolation cash flow provides no indication as to the level of underlying profitability. As shown in Chapter I, earnings when compared to capital employed provide a true measure of the average returns that are being generated by the assets in the sector at any point in time.

Industry earnings are extremely vulnerable to lower prices

Upstream earnings are even more leveraged than cash flows to changes in oil and gas prices because of the high and fixed nature of D&D charges (barring writedowns in the value of the assets being depleted). Again, the key perspective is the vulnerability of the sector to lower prices. Net earnings in 1991 are projected to fall to a nominal $220 million, from $1.8 billion in 1990. Under the low price scenario, net losses are incurred through the entire 1992-1995 period. The substantial growth in earnings projected under the high price scenario stands in sharp contrast, increasing steadily every year to nearly $2.7 billion in 1995.

Figure IV.10



Source: Historical data from PMA.

Capital Expenditures

We have projected levels of capital expenditures based on the following considerations:

1. *Current investment economics*, which determines the general overall attractiveness of exploring and developing new reserves (discussed below).

2. *Internally generated cash flow*, which is assumed to provide an upper bound on conventional investment over the medium-term.

3. *Major projects*, which are underway, are treated explicitly.

Major projects will buoy capital investment over the next few years

Based on drilling activity to date and estimated spending on the Caroline and Husky upgrader projects, investment in Western Canada in 1991 is expected to be in the order of $6.4 billion, up over 6% from last year. Without the Caroline and Husky upgrader projects--total estimated expenditures of about $1 billion in 1991--spending would very likely be down from last year. Exploration for gas has slowed markedly due to current depressed prices.

Total upstream expenditures are estimated to be about $7.1 billion in 1991, which include the Hibernia and Cohasset Panuke projects--about $540 million--and maintenance capital in the oil sands. This is about 17% greater than the cash flow the industry is expected to generate this year.

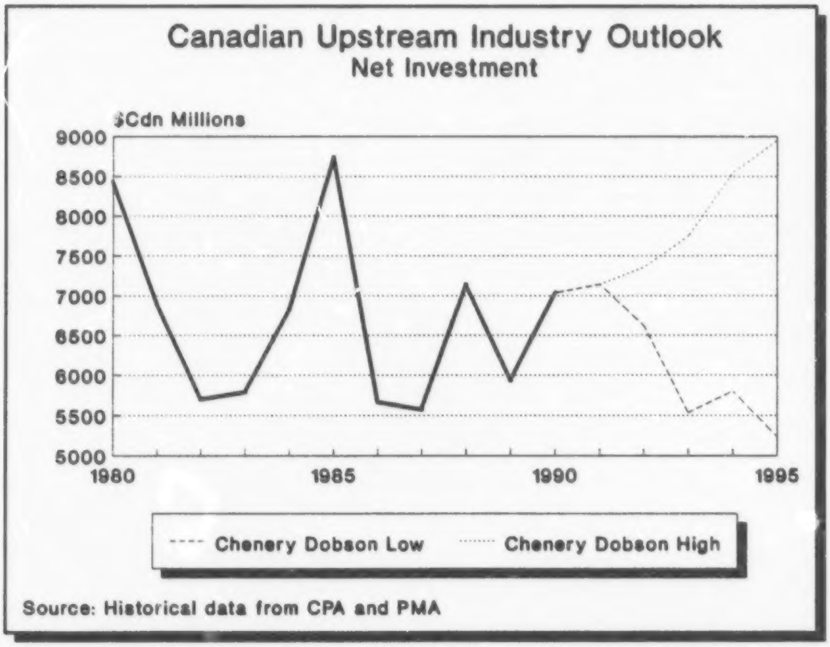
Under the low price scenario, investment in conventional areas is expected to contract dramatically due to the combination of lower cash flows and poor investment economics. Expenditures on Caroline and the Upgrader--total of about $600 million--continue to buoy up levels in 1992 but the total is still expected to

Capital expenditures in Western Canada would be severely depressed under the low price scenario

be down 13% to about $5.5 billion. When combined with the sizable outlays for Hibernia--$800 million--total Canadian investment in 1992 is expected to be $6.6 billion, 27% or $1.4 billion above the cash flow projected to be generated by the industry. Over the remainder of the forecast horizon, Hibernia is expected to be the only major project on the books with expenditures of $800 million in 1993, $1.2 billion in 1994 and $500 million in 1995. *Conventional spending is projected to drop to an average of about $4.5 billion per year over this period. These levels would be a post-1980 low for the industry. Even with these reductions, total investment is projected to exceed cash flows by 10% and 12% respectively in 1993 and 1994.*

Obviously, the investment climate is considerably more favourable under the high price scenario. The major differences between the two scenarios is primarily a function of the larger cash flows available for reinvestment and much more favourable investment economics. With higher prices, total upstream investment is projected to grow steadily over the forecast horizon, to a total of $8.9 billion by 1995.

Figure IV.11


Canadian Upstream Industry Outlook
Net Investment

Source: Historical data from CPA and PMA

Discretionary investment would be very low under the low price scenario

It should be emphasized that these projected depressed levels of capital investment embody very low levels of discretionary, new project investment. The industry has maintenance capital requirements that run at an estimated $2-$3 billion per year. This capital is required to maintain the efficient operation of older fields, meet contractual obligations for natural gas, comply with existing environmental guidelines and to do the drilling necessary to avoid relinquishing lease positions. Under our low price scenario, we estimate that discretionary spending would be a relatively low $1.5 to $2.5 billion per year. This could potentially be the lowest level of discretionary capital spending in the upstream sector of Canada since the mid-1970's.

As an important qualification to the above, the industry will always have some profitable new projects to pursue, resulting more than anything from past exploration successes. This should maintain a certain base level of discretionary spending. It is also important to recognize that while the sector as a whole is likely to show little growth and may even contract over the first half of the 1990's, certain companies will continue to grow strongly. ***There are several intermediate and senior companies with excellent F&D records, and a burgeoning group of well managed junior companies, which have the potential to be relatively profitable in the current price environment.***

Investment Economics

We have assessed the economics of exploring and developing oil and gas reserves in Alberta under the two price scenarios discussed above and under various F&D costs (see Appendix VII). We have utilized our reference reserve models which are representative of a typical single well oil and gas pool discovery in Alberta. The invested capital is full cycle, considering both exploration and development expenditures, with total amounts based on the assumed F&D and allocated based on average long term industry breakdown of exploration and development (E&D) capital. An estimate of general and administrative expenses is included and the economics are all after income taxes. For oil, investments are made in 1991 with production commencing in January of 1992 while gas investments occur over 1991 and 1992 with production commencing in January of 1993.

Figure IV.12 illustrates the impact of various F&D costs on a light oil project's internal rate of return (IRR) under the two price scenarios. Under the high price scenario, oil project IRR's range from 39% at $3.00/B F&D costs to 4% at $15.00/B F&D. Under the low price scenario, project IRR's range from 32% to 1% under the same F&D range. ***The level of F&D costs where returns satisfy the industry's historical cost of capital are $7.00 to $8.25 for the low and high price scenarios respectively.***

Figure IV.12

Oil investmeent economics are marginal under both price scenarios based on average industry F&D costs

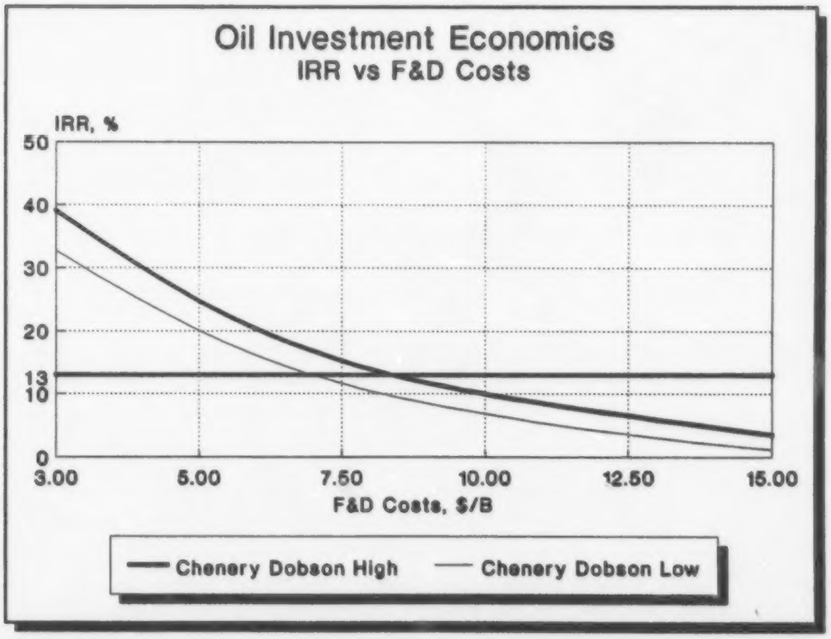
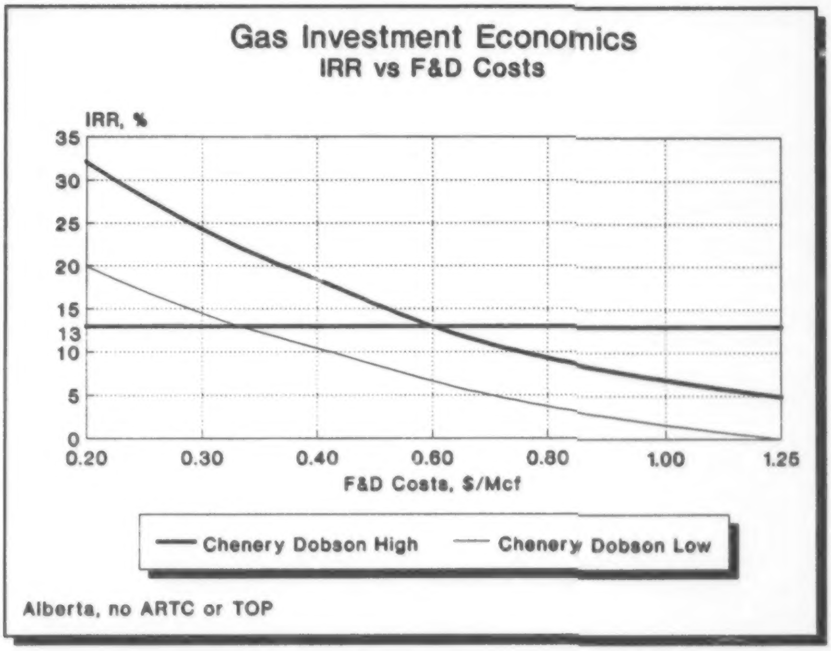


Figure IV.13 presents gas economic returns under a range of full cycle investment costs. ***For a typical gas reservoir in Alberta, the results indicate that F&D costs of $0.33/Mcf and $0.60/Mcf must be achieved with the low and high prices respectively to satisfy the industry's historical cost of capital.***

Figure IV.13

Under low price scenario, gas investment economics are very tenuous



The principal conclusions drawn from this analysis should come as no surprise.

- The industry average F&D costs discussed in Chapter II indicated that F&D costs for conventional oil in 1990 were well above $10/B. If this estimate is reasonably correct, it is apparent that it will be fairly difficult for the industry to generate acceptable rates of return on future conventional oil exploration even under the high price scenario.

- For conventional heavy oil to be profitable, F&D costs (mostly development costs since most heavy oil deposits are readily identifiable) must be kept at very low levels to offset the lower prices that these poorer quality grades of oil receive. ***This conclusion has serious consequences for industry profitability. As the potential for new light oil reserves declines with the maturing of the Western Canadian sedimentary basin, companies will increasingly have to replace production with new reserves that are heavier and of lower quality.***

- Based on average gas F&D costs of $0.52/Mcf in 1990, full cycle economics for natural gas are very tenuous under the low price scenario. This type of forecast is receiving increasing credence in the industry due to the extreme weakness in prices to date in 1991 and is very likely to have a negative impact on gas directed capital expenditures over the near to medium-term.

The general picture that emerges is that investment economics for oil and gas in Canada are relatively poor. This will definitely be a factor that will constrain future capital spending. The qualification to this view is to recognize the wide variance in F&D costs across the many companies operating in the industry. Some companies will continue to add new reserves at low costs, and the related investment capital will generate attractive returns. However, for the industry as a whole it will be a challenge to add new reserves at a cost that will generate acceptable returns.

Key Implications

i) Industry Profitability

Under the projected investment profiles, the capital employed by the upstream Canadian industry remains fairly stagnant over the next five years, particularly when contrasted with the explosive growth of the late 1970's and early 1980's. We would note that our estimates of future capital employed ignore all writedowns and corporate acquisitions that may occur over the forecast horizon. Under the low price scenario, capital employed is expected to remain flat at about the $60 billion level over the forecast horizon. Capital employed would increase modestly under the high price scenario, due to higher investment levels, to about the $68 billion level by 1995.

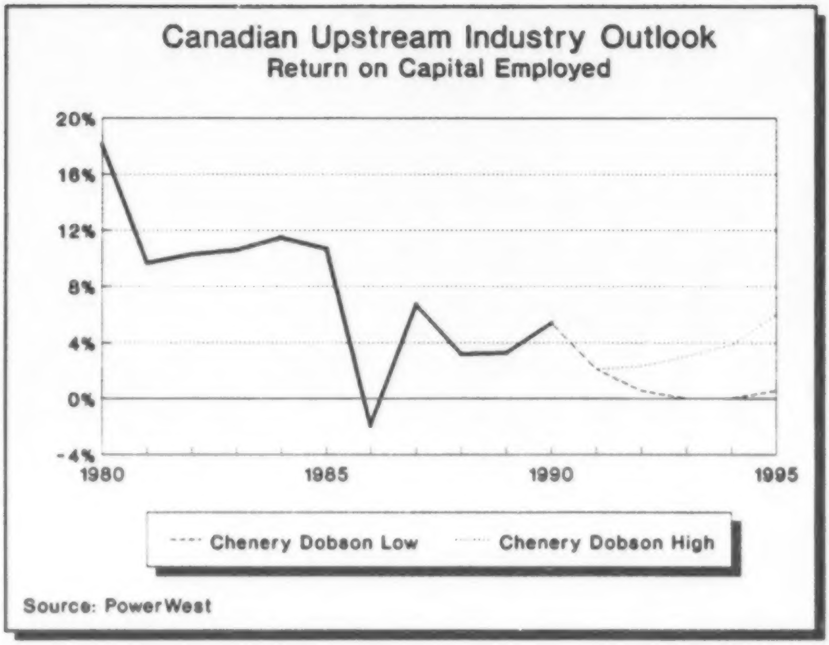
Future returns on capital are calculated by applying the definitions described in Chapter 1. ***Based on the projections described above, we see very little scope for the industry to establish adequate levels of profitability through the first half of the 1990's. The extremely low level of earnings projected under the low price scenario result in essentially negligible ROCE's over the entire forecast horizon. The projected losses over the 1992-1995 period result in negative ROE's. This again underscores the vulnerability of the Canadian upstream industry to a future where there is only minimal growth in nominal oil and gas prices. Even under the high price scenario, ROCE's remain very poor, below 4% through 1994 and growing to 6% in 1995.***

Impending environmental initiatives are a negative for industry profitability

The growing concern over the environment has extremely important but unfortunately negative implications for the profitability of the upstream Canadian industry. At this point in time it is very difficult to quantify the impact of the policy initiatives now being considered and we have therefore not explicitly included them in our analysis. However, the general trend is clear. Tighter environmental standards will lead to higher costs, both capital and operating, and increased delays, complexities and costs associated with more regulation. These burdens will magnify the mounting cost pressures that the industry already faces, and prospects are very poor that the industry will be able to earn a return on these expenditures. Canadian oil and gas producers are price takers for both oil and gas and the higher costs of complying with stricter environmental standards will be very difficult to pass through to consumers unless they are equally borne by U.S. and international competitors. A broader discussion of the environment and its implications for the oil and gas sector is provided in Appendix VIII.

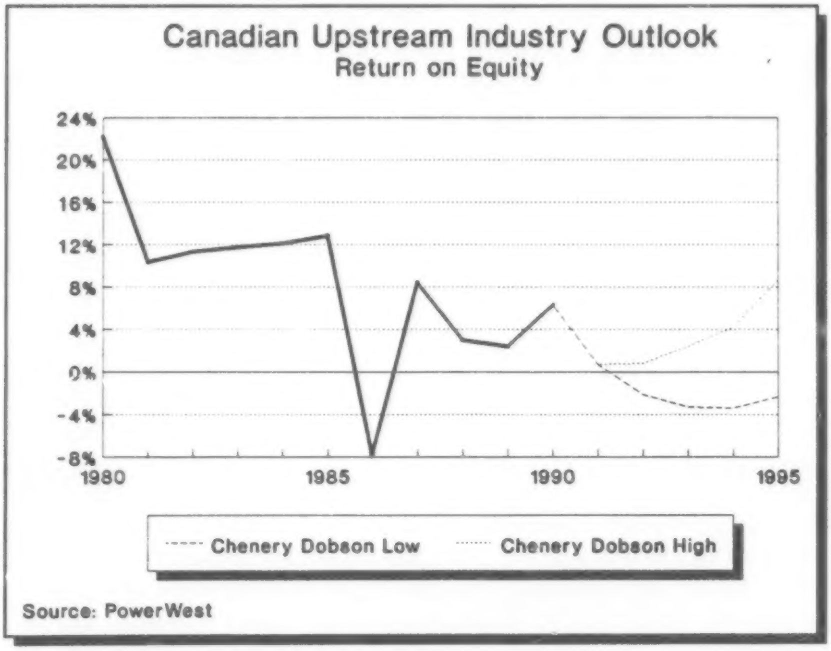
Figure IV.14

Industry profitability remains poor through 1995 under both price scenarios



Source: PowerWest

Figure IV.15



Source: PowerWest

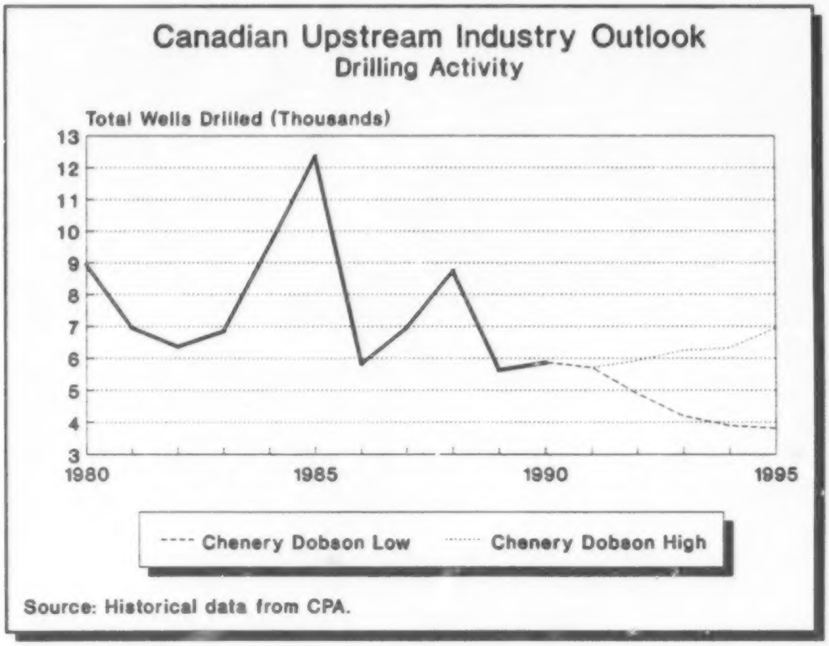
ii) Drilling Activity

Drilling costs per foot are assumed to escalate with inflation over the forecast horizon. This may in fact prove to be somewhat conservative under the more aggressive price scenario. The drilling sector is also financially distressed at this point in time and would look to impose substantial price increases if activity levels warranted.

Drilling activity would be severely depressed under the low price scenario

Based on the projected levels of capital spending, conventional drilling activity would be severely depressed under the low price scenario. The combination of higher drilling costs and lower spending would push down the total number of wells drilled to about 4,000 per year over the 1993 to 1995 period. One has to go back to 1975 to find a comparable level of activity. This contraction in activity would have dire consequences for the service sector which is currently financially distressed even with activity levels that are about 50% higher than projected levels. Drilling activity is expected to steadily increase under the high price scenario, to about 7,000 wells drilled per year by 1995. Growth is not as pronounced as otherwise might be expected because of the assumed increases in drilling costs.

Figure IV.16



Source: Historical data from CPA.

iii) Reserve Replacement

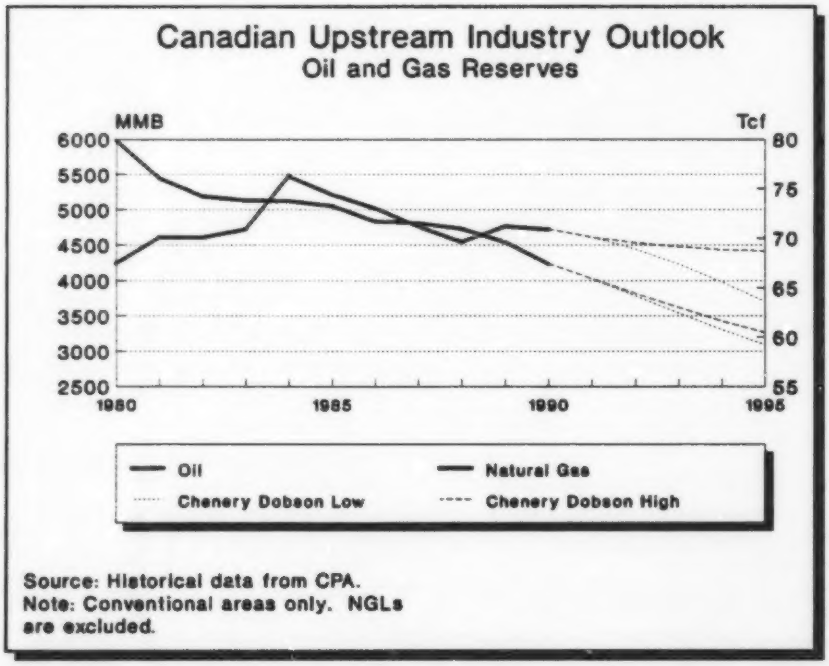
Finding rates (defined as reserves found per well drilled) are assumed to remain flat over the forecast horizon. Although traditional geological theory suggests that finding rates would tend to fall over time because of the tendency for larger fields to be discovered early in the development process, recent experience has actually seen the reverse. There are several reasons for this, most notably the high grading of prospects in an environment of lower activity and advances in technology. In addition it is also possible that the current phase of development within the WCSB is one in which there is a large number of similarly sized (albeit small) pools remaining to be discovered.

Finding and development costs are projected using the same general methodology that is employed to calculate historical estimates. The assumptions of flat finding rates and 5% escalation in drilling costs implies that F&D costs will also increase with inflation over the forecast horizon. Quite broadly, if F&D costs are to decline in real-terms in future years, the industry must find more reserves per unit of drilling effort. This would require the discovery of more large pools like Caroline or further improvements and/or increased successful application of technologies like 3-D seismic which reduce dry hole costs.

Every company producing oil and gas is faced with the dilemma that its principal asset, oil and gas reserves, are constantly shrinking unless replenished (or grown) with new reserves. New reserves can only be established through exploration and development, or through acquisition. For the industry as a whole, investment is the only means to prevent the reserve base and production from shrinking. In a high cost basin like Canada, capital spending must be particularly high to prevent this from happening. To put this into perspective, at current F&D costs of roughly $8.50/BOE, the industry would have to spend $8.5 billion per year to maintain the conventional reserve base. Since 1986, conventional spending has averaged $5.5 billion per year and just reaches the $8.5 billion per year level by 1995 under our high price scenario.

Figure IV.17

Industry investment is inadequate to maintain the reserve base even under a high price scenario



Source: Historical data from CPA.
Note: Conventional areas only. NGLs are excluded.

There is little doubt that the Canadian upstream industry faces a major challenge to match even this relatively poor performance over the next decade. ***Our projections indicate that Western Canadian oil and gas reserves will shrink over the forecast horizon under both price scenarios. The expected decline in conventional crude oil*** *reserves is particularly acute, due largely to low finding rates and low activity levels relative to the 1980's. Natural gas reserves are expected to be much more resilient as the general consensus is that the undiscovered gas potential in the WCSB is considerable.*

Sensitivity Analysis

For illustrative purposes, we have examined the industry outlook under a wide array of alternative scenarios to establish a better understanding of what possible conditions might generate acceptable levels of profitability over the next five years. The cases examined and key results of this sensitivity analysis are provided in the table below.

Table IV.2

SENSITIVITY ANALYSIS SUMMARY

	1992	1993	1994	1995
Base Cases				
Low Prices				
ROCE's	0.6%	0.0%	0.0%	0.6%
ROE's	-2.1%	-3.3%	-3.4%	-2.3%
High Prices				
ROCE's	2.3%	3.0%	3.8%	6.0%
ROE's	0.8%	2.4%	4.2%	8.7%
Sensitivity Cases				
	$US/B WTI			
What level of oil prices are required to generate 12% ROCE's if gas prices were at $2/Mcf?	36.0	37.5	41.0	42.5
What level of oil prices are required to generate 12% ROCE's if gas prices were at $3/Mcf?	31.5	33.5	36.0	38.5
High Price Cases Only:				
What if operating costs were constant?(1)				
ROCE's	3.0%	4.2%	5.3%	7.8%
ROE's	2.3%	4.8%	7.4%	12.3%
What if reinvestment was 50% of cash?				
ROCE's	3.0%	3.8%	4.8%	7.5%
ROE's	2.3%	4.7%	7.0%	11.6%
What if operating costs were constant and reinvestment was 50% of cash?				
ROCE's	3.7%	5.0%	6.4%	9.5%
ROE's	3.7%	6.8%	9.7%	14.5%

Notes: 1. Capital spending maintained as per high price scenario.

Prices required to generate acceptable profitability over the next five years are well beyond reasonable expectations

Extreme cost cutting measures and reduced capital outlays are necessary but not sufficient to restore acceptable levels of profitability

The key results of this analysis are as follows:

- *The level of prices required to generate acceptable profitability over the next five years are well beyond even the most aggressive forecasts.*

- *If the industry is able to hold operating costs constant over the forecast horizon, returns still remain well below acceptable levels through the forecast period, even under the high price forecast.*

- *Reducing capital spending to 50% of internal cash flow has roughly the same impact as constant operating costs. This results in a shrinking capital base that allows the industry to generate substantially higher returns with the same level of income. Based on this factor above, returns are still unacceptably low, again even under the high price scenario.*

- *If the industry manages to hold operating costs constant and dramatically scales back re-investment levels to about 50% of available cash flow, then profitability starts to approach acceptable levels by the mid-1990's. Again, though, this is only in the aggressive high price scenario. If the low price scenario prevails, even draconian cost containment and investment curtailment plans will not restore acceptable levels of profitability.*

- *These scenarios all assume no change to the existing fiscal regime. Under all scenarios, reduced royalties have the potential to make a significant contribution to improved profitability.*

APPENDICES

APPENDIX I

THE LINK BETWEEN ACCOUNTING MEASURES OF PROFITABILITY AND PROJECT RETURNS

OBJECTIVE

We have evaluated commonly used accounting measures of profitability and their relationship to project returns. The objective of this analysis was to determine whether accounting returns provide a meaningful measure of a firm's overall financial status at a point in time.

Approach

In our analysis, we employed a rigorous approach to prove, with a minimum of ambiguity, that there is in fact a link between accounting and project returns.

We utilized our investment economic model, described in detail in Appendix VII, to calculate the yearly accounting returns generated by a project under various investment scenarios.

Two cases were created to contrast accounting returns; the base case where all cash generated by the project is fully dispersed, and the reinvestment case where cash is reinvested. The two cases are described in detail as follows:

Base Case

The project was assumed to be a single asset company, having a capital structure with a debt:equity ratio of 40:60, typical of an operating oil and gas company. This ratio was held constant over the life of the project. Taxes were calculated on a stand alone basis at current Canadian and Alberta statutory rates.

In the Base Case, all after tax cashflow generated by the project was used to repay corporate debt with the balance paid out as common dividends, in a ratio consistent with the debt:equity ratio. An interest rate of 10% was used, roughly equal to current long term rates available in Canada. Through maintaining a constant debt:equity ratio and dispersing all residual cash in a like ratio, the company was essentially liquidated by the end of the project life. Based on the above assumptions, financial statements were created for the project.

Key yearly accounting measures of profitability were calculated from these statements, based on year-end figures and the following definitions:

$$\text{Return on Equity (ROE)} = \frac{\text{Net Income}}{\text{Shareholder's Equity}}$$

$$\text{Return on Capital Employed (ROCE)} = \frac{(\text{Net Income} + \text{Deferred Taxes} + \text{After Tax Interest})}{(\text{Long Term Debt} + \text{Shareholders Equity})}$$

The Base Case was created to observe the above measures on a year over year basis for a liquidating firm, an business philosophy not commonly eschewed by publicly traded oil and gas companies.

Reinvestment Case

The reinvestment case was created to be more typical of an ongoing firm's business philosophy, and to establish the link between the Internal Rate of Return (IRR) of a project and accounting returns. In this case, cash generated by the project above debt repayment is reinvested in other income generating projects.

The base case was adjusted so that after debt repayment, no dividends were paid out and instead the cash was reinvested by the company to earn an after tax rate of return equal to the project's IRR, as calculated in the investment economics. This is representative of growth oriented oil and gas companies who generally reinvest 100% or more of available cash flow. These investments are in projects expected to yield, at minimum, the prevailing investment hurdle rate (average cost of working capital plus a risk premium) implied by the company's capital structure.

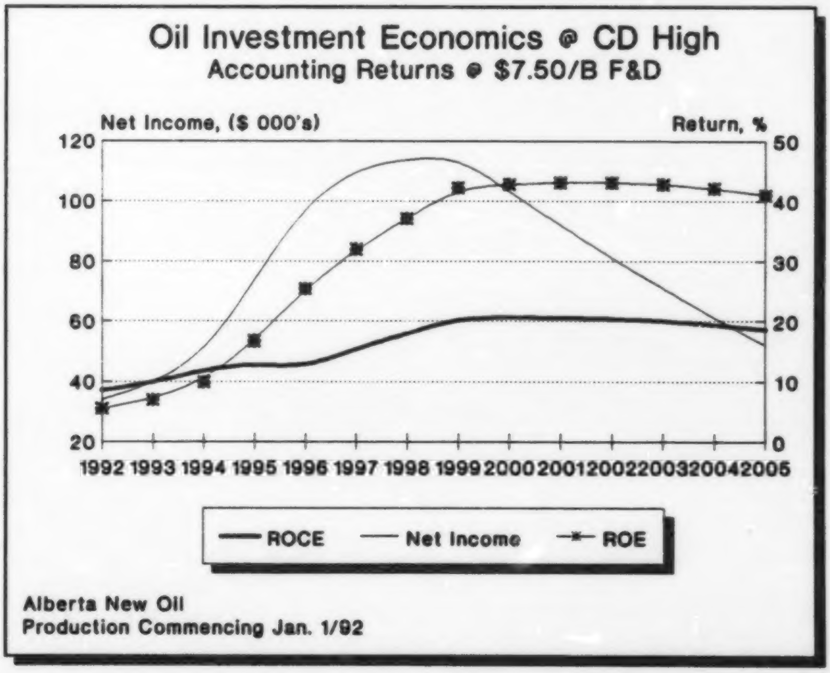
The capital structure was not kept constant in this case, to avoid the company incurring the large debt infusions required to maintain the debt:equity ratio at 40% as the company grows.

Results

The accompanying graphs illustrate the results of the analysis for a $7.50/B F&D cost oil project, under the Chenery Dobson (CD) High price forecast which generates an IRR of 15.5% (see Appendix VI).

The first graph presents the Base Case results for the first 14 years of the project. As shown, over the first years of the project net income rises substantially as commodity price increases outweigh production declines and inflation. Over this same period, although lagging somewhat, both ROE and ROCE also increase at high rates. The returns taper off in later years as the price forecast assumes flat nominal crude prices after 1999. Under a price forecast where crude prices remained constant on a real basis over the longer-term, the accounting measures would continue to increase.

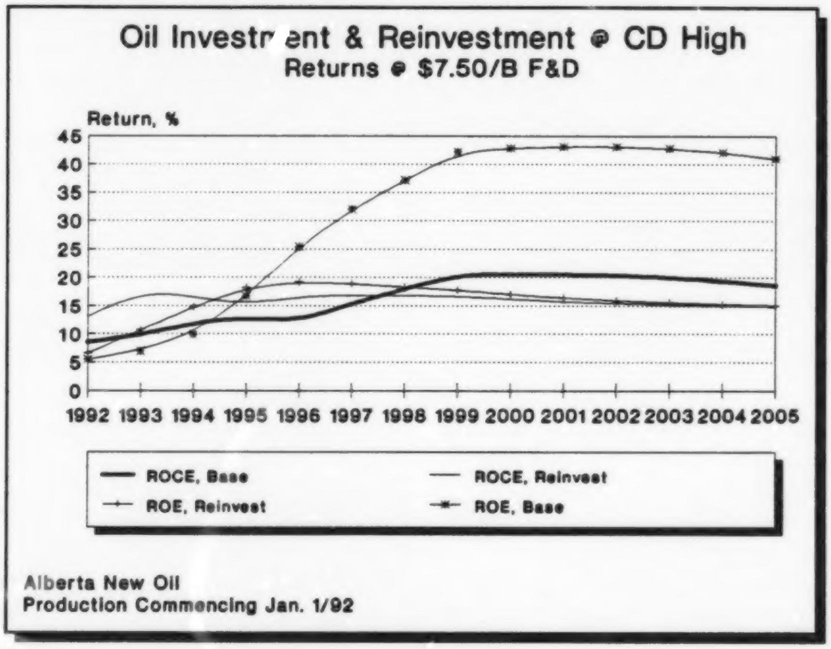
Figure APPI.1



Increasing accounting returns reflect the liquidating nature of the company. The capital base (the elements of which comprise the denominator in the accounting return calculations) shrinks over time with the payout of all cash flow generated by the project, and no other sources of revenue.

The second graph compares the accounting returns generated in the Base Case to those generated in the Reinvestment Case. As shown, with continuous reinvestment of cash which yield IRR's equal to that of the project (and commiserate with financial theory), the accounting measures converge to that prevailing IRR, in this case about 15.5%. The returns stabilize in the reinvestment case as the capital base increases with corporate growth.

Figure APPI.2



Oil Investment & Reinvestment @ CD High
Returns @ $7.50/B F&D

Alberta New Oil
Production Commencing Jan. 1/92

In our opinion, this empirical analysis establishes a link between accounting measures of profitability and project returns. In theory, the analysis implies that oil and gas companies, over time, should yield accounting measures of profitability equal to the hurdle rate of their investments.

The reinvestment case illustrates the trend of accounting returns from the beginning of the project's life into a steady state period. However, we would make the point that most of the intermediate and senior oil and gas companies are currently established and already into this steady state period, such that the accounting measures of profitability should reflect the IRR of their portfolio of investments. The fact that a substantial number of companies, and the industry in general, are generating inadequate returns below implied costs of capital, suggests that past investments have not performed as expected. The reasons for this are discussed at length in the main body of the report.

APPENDIX II

COST OF EQUITY AND CAPITAL

COST OF CAPITAL

In order to determine a cost of capital for the industry, we have applied a market based methodology to determine the cost of debt and to determine an appropriate "risk premium" required for the added risk to equity holders. In dealing with the cost of debt, the after-tax cost of debt was calculated utilizing actual industry data and the statutory tax rate for each year from 1979 to 1990. Prior to 1979 we estimated the cost of debt using average corporate bond yields from each year.

The "risk premium" approach to the cost of equity is based on the notion that investors require a higher return from risky assets than from riskless assets. The principle being that returns from risky assets need to generate higher returns than riskless assets in order to attract capital. To determine an appropriate premium for equity investors, we analyzed Toronto Stock Exchange data and Canadian T-bill data (the riskless asset) from 1947 to the present to understand the actual market premium prevailing over that period. The risk premium fluctuates over time dependent on economic conditions, market expectations and the level of interest rates.

Over the 1947-1990 period, the average observed risk premium was 6.1% based on average total returns from equities of 12.1% and the average risk free rate of 6.0%. We also observed that, more recently, risk premiums have declined from their long-run historical average. For example, during the period from 1976 to the present, the risk premium for Canadian equities has averaged approximately 4.3%. During periods of fluctuating interest rates, there is an inverse relationship between the risk premium and the risk free rate. Empirically, studies have found that for each 1% rise in interest rates above the normal mean, the risk premium falls by 50 to 65 basis points. The following table summarizes the differentials between total returns from the TSE 300 and 90 day Canada T-bills over various periods between 1947 to 1990.

Table APPII.1

RISK PREMIUMS
Differentials between TSE 300
Returns and 90 day Canada T-bills

	TSE 300 Total Returns	Risk Free Rate	Risk Premium
1947 to 1990	12.1	6.0	6.1
1951 to 1990	11.7	6.6	5.1
1956 to 1990	11.0	7.3	3.7
1961 to 1990	12.2	7.9	4.3
1966 to 1990	11.4	8.8	2.6
1971 to 1990	13.0	9.5	3.5
1976 to 1990	15.1	10.8	4.3
1981 to 1990	11.0	11.2	-0.2

Notes:
1. TSE 300 total returns include dividends and capital appreciation.
2. The risk free rate is the average yield from 90 day Canada T-bills.

The above results indicate that investors can expect to receive, on average, a premium of at least 3.7% for their market portfolio. In order to determine the cost of equity capital that is appropriate for the oil and gas industry in Canada, we need to adjust the risk premium for the market by an amount that accurately reflects the unique business risks of the industry. The appropriate adjustment is captured in the "Beta" that can be calculated (using the TSE Oil and Gas Index as a proxy for the whole industry) from the "excess" returns generated by the TSE Oil and Gas Index that are above (or below) those generated by the overall market. The results of this work are summarized in the table below.

Table APPII.2

BETA ESTIMATES
Canadian Oil & Gas Industry

Period	Beta	R Squared	SEE	STD	Number of Observations
1956 to 1961	1.27	0.73	0.0303	0.174	60
1961 to 1966	0.84	0.54	0.0241	0.155	60
1966 to 1971	1.48	0.59	0.0506	0.225	60
1971 to 1976	1.37	0.74	0.0424	0.206	60
1976 to 1981	1.38	0.70	0.0464	0.215	60
1981 to 1986	1.20	0.61	0.0496	0.223	60
1986 to 1991	0.91	0.48	0.0449	0.212	60
1956 to 1991	1.24	0.62	0.0432	0.208	425

Notes:
1. SEE is the standard error of the estimate.
2. STD is the standard deviation of the beta.
3. Frequency of observations is monthly.

Utilizing the above Betas and the risk premiums for the overall market indicates that the risk premium appropriate for the Canadian oil and gas industry is in the range of 3.0% to 6.5%. These results are indicative of the wide fluctuations that can occur in the market due to changing expectations at different points in time. Expectations are generally influenced by changes to inflation expectations, changes in the taxation of different securities, or by changes to existing regulations governing the industry. The following table illustrates yearly expectations of equity investors in the oil and gas business. This is a forward looking concept and is the result of historical returns from the market and the prevailing level of interest rates.

The following table also provides estimates of the cost of debt, the cost of equity, and the cost of capital for the industry based on the expected costs (or opportunity costs) for each year from 1970. The weighted cost of capital is calculated from the relative weights of debt and equity to the total capital of the industry. For the period from 1979 to 1990 we have used actual PMA data to determine the relative levels of debt and equity and used the same data to measure the cost of debt each year.

Investment Weighted Cost of Capital

In recognition of the fact that returns on capital in the industry are a combination of the returns earned on capital that has been employed in the current as well as all previous years, the investment weighted cost of capital weights each previous year's cost of capital by the dollar value of investment in that year. Investment capital in the weighting formula is amortized over twenty years. This approach smooths the cost of capital over time, recognizes the longer-term nature of investments and return and appropriately matches returns with the capital employed to earn those returns.

Table APPII.3

OPPORTUNITY COST OF CAPITAL

Year	Risk Free Rate	Corporate Bond Yields	CAPM Industry Opportunity Cost of Capital	Implied Cost of Debt	Implied Cost of Equity	Capital Structure		Beta e
						Debt	Equity	
1970	5.69	8.62	9.5	4.5	11.7	30%	70%	1.48
1971	3.45	7.80	7.0	4.1	8.2	30%	70%	1.37
1972	3.59	8.22	7.1	4.3	8.3	30%	70%	1.37
1973	5.70	8.52	9.2	4.5	11.3	30%	70%	1.37
1974	7.83	9.92	11.4	5.2	14.0	30%	70%	1.37
1975	7.59	10.04	11.1	5.3	13.7	30%	70%	1.37
1976	8.83	9.99	12.4	5.2	15.5	30%	70%	1.38
1977	7.22	9.63	10.8	5.0	13.3	30%	70%	1.38
1978	8.91	10.12	12.5	5.3	15.6	30%	70%	1.38
1979	11.75	8.30	15.3	4.3	20.0	30%	70%	1.38
1980	12.75	10.50	16.4	5.5	20.7	28%	72%	1.38
1981	17.76	14.60	20.4	7.7	28.9	40%	60%	1.20
1982	13.81	17.20	16.6	9.0	21.1	37%	63%	1.20
1983	9.30	15.70	12.1	8.2	14.3	36%	64%	1.20
1984	11.06	15.00	13.8	7.9	17.5	38%	62%	1.20
1985	9.43	11.80	12.1	6.2	15.9	39%	61%	1.20
1986	8.97	12.00	11.0	6.3	14.2	41%	59%	0.91
1987	8.14	10.90	10.3	5.7	12.8	35%	65%	0.91
1988	9.48	11.30	11.8	6.5	14.2	31%	69%	0.91
1989	12.00	13.30	14.2	7.6	17.7	35%	65%	0.91
1990	12.78	12.30	15.0	7.1	19.1	34%	66%	0.91
Average 1970 to 1990			12.4	6.0	15.6			
Average 1980 to 1990			14.0	7.1	17.9			

Definitions:

1. Debt is all long term debt including convertible debentures (PMA).
2. Debt is valued at par (principal amount).
3. Equity includes preferred share capital.
4. Prior to 1979, capital structure is estimated.
5. The risk premium for the market portfolio was estimated to be 3.7%.
6. Oil industry betas have been calculated for each five year period from 1956.

Between 1970 and 1990, the lowest level of debt in the Canadian oil and gas industry was in 1980 when it represented 28% of the total debt and equity for the industry. The maximum level of debt was reached in 1986 when it accounted for 41% of the total debt and equity. In absolute terms, long term debt peaked in 1985 at $24.4 billion, slightly higher than the $24.0 billion for 1986.

Since 1979, we estimate that the average cost of equity for the industry has been approximately 17.9%. This reflects an average capital structure over the period of approximately one-third debt and two-thirds equity. For the same period, we estimate that the cost of equity for the overall market has averaged 16.2% and that the cost of equity for utilities has averaged 15.2%. Similarly, we estimate that the cost of capital for the oil industry has averaged 14.0% since 1979 while for the overall market and utilities it has averaged 12.6% and 12.1% respectively. The narrower spread for the average cost of capital reflects the higher use of debt by utilities and the overall market.

The following tables are included to illustrate the data and to demonstrate the calculations that were required for the cost of capital estimates. The same methodology was applied to calculated the opportunity cost of capital for the U.S. oil and gas companies represented in the S&P 500 Oil and Gas Index. It is interesting to note that the Beta for the U.S. industry was calculated to be substantially less than 1.0 (0.75), whereas the Betas estimated for the Canadian industry were generally above 1.0 and were, on average, approximately 1.2.

Canadian Risk Free Rate
Canada 90 day Treasury Bill Yields
Quarterly from 1947

1st/47	0.40	1st/56	2.64	1st/65	3.62	1st/74	6.51	1st/83	9.17
2nd/47	0.41	2nd/56	2.52	2nd/65	3.93	2nd/74	8.75	2nd/83	9.17
3rd/47	0.41	3rd/56	3.16	3rd/65	4.13	3rd/74	8.94	3rd/83	9.24
4th/47	0.41	4th/56	3.67	4th/65	4.54	4th/74	7.12	4th/83	9.71
1st/48	0.41	1st/57	3.70	1st/66	5.06	1st/75	6.33	1st/84	10.53
2nd/48	0.41	2nd/57	3.81	2nd/66	5.00	2nd/75	6.99	2nd/84	12.11
3rd/48	0.41	3rd/57	3.80	3rd/66	5.01	3rd/75	8.41	3rd/84	12.02
4th/48	0.41	4th/57	3.62	4th/66	4.96	4th/75	8.64	4th/84	9.84
1st/49	0.44	1st/58	2.27	1st/67	4.13	1st/76	9.07	1st/85	10.40
2nd/49	0.51	2nd/58	1.72	2nd/67	4.28	2nd/76	8.98	2nd/85	9.33
3rd/49	0.51	3rd/58	2.27	3rd/67	4.76	3rd/76	9.11	3rd/85	8.75
4th/49	0.51	4th/58	3.49	4th/67	5.95	4th/76	8.14	4th/85	9.24
1st/50	0.51	1st/59	4.30	1st/68	6.98	1st/77	7.54	1st/86	10.19
2nd/50	0.51	2nd/59	5.11	2nd/68	6.56	2nd/77	7.07	2nd/86	8.59
3rd/50	0.61	3rd/59	5.50	3rd/68	5.66	3rd/77	7.10	3rd/86	8.35
4th/50	0.63	4th/59	5.12	4th/68	6.24	4th/77	7.17	4th/86	8.24
1st/51	0.75	1st/60	3.01	1st/69	6.58	1st/78	7.73	1st/87	6.80
2nd/51	0.75	2nd/60	3.07	2nd/69	7.13	2nd/78	8.26	2nd/87	8.29
3rd/51	0.86	3rd/60	1.70	3rd/69	7.77	3rd/78	9.17	3rd/87	9.35
4th/51	0.90	4th/60	3.25	4th/69	7.81	4th/78	10.46	4th/87	8.41
1st/52	0.93	1st/61	3.21	1st/70	7.00	1st/79	10.92	1st/88	8.53
2nd/52	1.07	2nd/61	2.57	2nd/70	5.94	2nd/79	10.78	2nd/88	9.19
3rd/52	1.12	3rd/61	2.59	3rd/70	5.39	3rd/79	11.64	3rd/88	10.33
4th/52	1.30	4th/61	2.99	4th/70	4.44	4th/79	13.66	4th/88	10.94
1st/53	1.52	1st/62	3.12	1st/71	3.16	1st/80	15.24	1st/89	12.14
2nd/53	1.71	2nd/62	5.45	2nd/71	3.37	2nd/80	10.38	2nd/89	12.08
3rd/53	1.97	3rd/62	4.99	3rd/71	4.06	3rd/80	10.95	3rd/89	12.23
4th/53	1.89	4th/62	3.91	4th/71	3.21	4th/80	17.01	4th/89	12.22
1st/54	1.59	1st/63	3.62	1st/72	3.57	1st/81	16.44	1st/90	13.26
2nd/54	1.49	2nd/63	3.24	2nd/72	3.50	2nd/81	18.83	2nd/90	13.58
3rd/54	1.16	3rd/63	3.56	3rd/72	3.62	3rd/81	19.35	3rd/90	12.40
4th/54	1.06	4th/63	3.78	4th/72	3.65	4th/81	14.41	4th/90	11.47
1st/55	1.09	1st/64	3.88	1st/73	4.46	1st/82	15.07		
2nd/55	1.44	2nd/64	3.59	2nd/73	5.48	2nd/82	16.33		
3rd/55	1.83	3rd/64	3.73	3rd/73	6.50	3rd/82	12.73		
4th/55	2.56	4th/64	3.82	4th/73	6.35	4th/82	9.80		

Source: Statistics Canada

Long Run Opportunity Cost of Capital

Year	Risk Free Rate	Corporate Bond Yields	CAPM Industry Opportunity Cost of Capital	Implied Cost of Debt	Implied Cost of Equity	Capital Structure Debt	Capital Structure Equity	Equity Beta
1947	0.41	3.47	5.4	1.8	7.0	30%	70%	1.20
1948	0.41	3.86	5.5	2.0	6.9	30%	70%	1.20
1949	0.49	3.76	5.5	2.0	7.1	30%	70%	1.20
1950	0.57	3.78	5.6	2.0	7.2	30%	70%	1.20
1951	0.82	4.20	5.9	2.2	7.4	30%	70%	1.20
1952	1.11	4.48	6.1	2.3	7.8	30%	70%	1.20
1953	1.77	4.61	6.8	2.4	8.7	30%	70%	1.20
1954	1.33	4.02	6.4	2.1	8.2	30%	70%	1.20
1955	1.73	4.07	6.8	2.1	8.8	30%	70%	1.20
1956	3.00	4.57	8.3	2.4	10.9	30%	70%	1.27
1957	3.73	5.00	9.1	2.6	11.8	30%	70%	1.27
1958	2.44	5.08	7.8	2.7	10.0	30%	70%	1.27
1959	5.01	6.10	10.3	3.2	13.4	30%	70%	1.27
1960	2.76	6.01	8.1	3.1	10.2	30%	70%	1.27
1961	2.84	5.92	6.4	3.1	7.8	30%	70%	0.84
1962	4.37	6.06	7.9	3.2	9.9	30%	70%	0.84
1963	3.55	5.98	7.1	3.1	8.8	30%	70%	0.84
1964	3.76	6.07	7.3	3.2	9.0	30%	70%	0.84
1965	4.06	6.14	7.6	3.2	9.5	30%	70%	0.84
1966	5.01	6.59	11.2	3.5	14.6	30%	70%	1.48
1967	4.78	6.92	11.0	3.6	14.2	30%	70%	1.48
1968	6.36	7.75	12.6	4.1	16.2	30%	70%	1.48
1969	7.32	8.62	11.2	4.5	14.0	30%	70%	1.48
1970	5.69	8.62	9.5	4.5	11.7	30%	70%	1.48
1971	3.45	7.80	7.0	4.1	8.2	30%	70%	1.37
1972	3.59	8.22	7.1	4.3	8.3	30%	70%	1.37
1973	5.70	8.52	9.2	4.5	11.3	30%	70%	1.37
1974	7.83	9.92	11.4	5.2	14.0	30%	70%	1.37
1975	7.59	10.04	11.1	5.3	13.7	30%	70%	1.37
1976	8.83	9.99	12.4	5.2	15.5	30%	70%	1.38
1977	7.22	9.63	10.8	5.0	13.3	30%	70%	1.38
1978	8.91	10.12	12.5	5.3	15.6	30%	70%	1.38
1979	11.75	8.30	15.3	4.3	20.0	30%	70%	1.38
1980	12.75	10.50	16.4	5.5	20.7	28%	72%	1.38
1981	17.76	14.60	20.4	7.7	28.9	40%	60%	1.20
1982	13.81	17.20	16.6	9.0	21.1	37%	63%	1.20
1983	9.30	15.70	12.1	8.2	14.3	36%	64%	1.20
1984	11.06	15.00	13.8	7.9	17.5	38%	62%	1.20
1985	9.43	11.80	12.1	6.2	15.9	39%	61%	1.20
1986	8.97	12.00	11.0	6.3	14.2	41%	59%	0.91
1987	8.14	10.90	10.3	5.7	12.8	35%	65%	0.91
1988	9.48	11.30	11.8	6.5	14.2	31%	69%	0.91
1989	12.00	13.30	14.2	7.6	17.7	35%	65%	0.91
1990	12.78	12.30	15.0	7.1	19.1	34%	66%	0.91
Average 1947 to 1990			10.0	4.3	12.7			
Average 1970 to 1990			12.4	6.0	15.6			
Average 1980 to 1990			14.0	7.1	17.9			

Definitions:

1. Debt is all long term debt including convertible debentures (PMA)
2. Debt is valued at par (principal amount)
3. Equity includes preferred share capital
4. Prior to 1979, capital structure is estimated
5. The risk premium for the market portfolio was estimated to be 3.7%
6. Oil industry betas have been calculated for each five year period from 1956

Long Run Opportunity Cost of Capital

Beta plus 1 standard deviation

Year	Risk Free Rate	Corporate Bond Yields	CAPM Industry Opportunity Cost of Capital	Implied Cost of Debt	Implied Cost of Equity	Capital Structure Debt	Capital Structure Equity	Equity Beta
1947	0.41	3.47	6.7	1.8	8.7	30%	70%	1.49
1948	0.41	3.86	6.7	2.0	8.7	30%	70%	1.49
1949	0.49	3.76	6.8	2.0	8.8	30%	70%	1.49
1950	0.57	3.78	6.8	2.0	8.9	30%	70%	1.49
1951	0.82	4.20	7.1	2.2	9.2	30%	70%	1.49
1952	1.11	4.48	7.4	2.3	9.5	30%	70%	1.49
1953	1.77	4.61	8.0	2.4	10.4	30%	70%	1.49
1954	1.33	4.02	7.6	2.1	9.9	30%	70%	1.49
1955	1.73	4.07	8.0	2.1	10.5	30%	70%	1.49
1956	3.00	4.57	9.0	2.4	11.9	30%	70%	1.44
1957	3.73	5.00	9.8	2.6	12.8	30%	70%	1.44
1958	2.44	5.08	8.5	2.7	11.0	30%	70%	1.44
1959	5.01	6.10	11.1	3.2	14.4	30%	70%	1.44
1960	2.76	6.01	8.8	3.1	11.2	30%	70%	1.44
1961	2.84	5.92	7.0	3.1	8.7	30%	70%	1.00
1962	4.37	6.06	8.6	3.2	10.9	30%	70%	1.00
1963	3.55	5.98	7.8	3.1	9.7	30%	70%	1.00
1964	3.76	6.07	8.0	3.2	10.0	30%	70%	1.00
1965	4.06	6.14	8.3	3.2	10.4	30%	70%	1.00
1966	5.01	6.59	12.2	3.5	15.9	30%	70%	1.71
1967	4.78	6.92	12.0	3.6	15.5	30%	70%	1.71
1968	6.36	7.75	13.5	4.1	17.6	30%	70%	1.71
1969	7.32	8.62	11.8	4.5	14.9	30%	70%	1.71
1970	5.69	8.62	10.1	4.5	12.5	30%	70%	1.71
1971	3.45	7.80	7.5	4.1	9.0	30%	70%	1.58
1972	3.59	8.22	7.7	4.3	9.1	30%	70%	1.58
1973	5.70	8.52	9.8	4.5	12.1	30%	70%	1.58
1974	7.83	9.92	11.9	5.2	14.8	30%	70%	1.58
1975	7.59	10.04	11.7	5.3	14.4	30%	70%	1.58
1976	8.83	9.99	12.9	5.2	16.2	30%	70%	1.59
1977	7.22	9.63	11.3	5.0	14.0	30%	70%	1.59
1978	8.91	10.12	13.0	5.3	16.3	30%	70%	1.59
1979	11.75	8.30	15.9	4.3	20.8	30%	70%	1.59
1980	12.75	10.50	17.0	5.5	21.5	28%	72%	1.59
1981	17.76	14.60	20.9	7.7	29.8	40%	60%	1.42
1982	13.81	17.20	17.1	9.0	21.9	37%	63%	1.42
1983	9.30	15.70	12.7	8.2	15.2	36%	64%	1.42
1984	11.06	15.00	14.3	7.9	18.3	38%	62%	1.42
1985	9.43	11.80	12.6	6.2	16.8	39%	61%	1.42
1986	8.97	12.00	11.4	6.3	15.0	41%	59%	1.12
1987	8.14	10.90	10.8	5.7	13.6	35%	65%	1.12
1988	9.48	11.30	12.3	6.5	15.0	31%	69%	1.12
1989	12.00	13.30	14.7	7.6	18.5	35%	65%	1.12
1990	12.78	12.30	15.5	7.1	19.9	34%	66%	1.12
Average 1947 to 1990			10.7	4.3	13.7			
Average 1970 to 1990			12.9	6.0	16.4			
Average 1980 to 1990			14.5	7.1	18.7			

Definitions:

1. Debt is all long term debt including convertible debentures (PMA)
2. Debt is valued at par (principal amount)
3. Equity includes preferred share capital
4. Prior to 1979, capital structure is estimated
5. The risk premium for the market portfolio was estimated to be 3.7%
6. Oil industry betas have been calculated for each five year period from 1956

Long Run Opportunity Cost of Capital

Beta minus 1 standard deviation

Year	Risk Free Rate	Corporate Bond Yields	CAPM Industry Opportunity Cost of Capital	Implied Cost of Debt	Implied Cost of Equity	Capital Structure		Equity Beta
						Debt	Equity	
1947	0.41	3.47	4.2	1.8	5.3	30%	70%	0.91
1948	0.41	3.86	4.2	2.0	5.2	30%	70%	0.91
1949	0.49	3.76	4.3	2.0	5.3	30%	70%	0.91
1950	0.57	3.78	4.4	2.0	5.4	30%	70%	0.91
1951	0.82	4.20	4.6	2.2	5.7	30%	70%	0.91
1952	1.11	4.48	4.9	2.3	6.0	30%	70%	0.91
1953	1.77	4.61	5.6	2.4	7.0	30%	70%	0.91
1954	1.33	4.02	5.1	2.1	6.5	30%	70%	0.91
1955	1.73	4.07	5.6	2.1	7.0	30%	70%	0.91
1956	3.00	4.57	7.6	2.4	9.9	30%	70%	1.10
1957	3.73	5.00	8.4	2.6	10.8	30%	70%	1.10
1958	2.44	5.08	7.1	2.7	8.9	30%	70%	1.10
1959	5.01	6.10	9.6	3.2	12.4	30%	70%	1.10
1960	2.76	6.01	7.4	3.1	9.2	30%	70%	1.10
1961	2.84	5.92	5.7	3.1	6.8	30%	70%	0.68
1962	4.37	6.06	7.2	3.2	9.0	30%	70%	0.68
1963	3.55	5.98	6.4	3.1	7.8	30%	70%	0.68
1964	3.76	6.07	6.6	3.2	8.1	30%	70%	0.68
1965	4.06	6.14	6.9	3.2	8.5	30%	70%	0.68
1966	5.01	6.59	10.3	3.5	13.2	30%	70%	1.25
1967	4.78	6.92	10.0	3.6	12.8	30%	70%	1.25
1968	6.36	7.75	11.6	4.1	14.8	30%	70%	1.25
1969	7.32	8.62	10.6	4.5	13.1	30%	70%	1.25
1970	5.69	8.62	8.9	4.5	10.8	30%	70%	1.25
1971	3.45	7.80	6.5	4.1	7.5	30%	70%	1.16
1972	3.59	8.22	6.6	4.3	7.6	30%	70%	1.16
1973	5.70	8.52	8.7	4.5	10.5	30%	70%	1.16
1974	7.83	9.92	10.8	5.2	13.2	30%	70%	1.16
1975	7.59	10.04	10.6	5.3	12.9	30%	70%	1.16
1976	8.83	9.99	11.9	5.2	14.7	30%	70%	1.17
1977	7.22	9.63	10.3	5.0	12.5	30%	70%	1.17
1978	8.91	10.12	11.9	5.3	14.8	30%	70%	1.17
1979	11.75	8.30	14.8	4.3	19.3	30%	70%	1.17
1980	12.75	10.50	15.9	5.5	19.9	28%	72%	1.17
1981	17.76	14.60	19.9	7.7	28.1	40%	60%	0.98
1982	13.81	17.20	16.1	9.0	20.3	37%	63%	0.98
1983	9.30	15.70	11.6	8.2	13.5	36%	64%	0.98
1984	11.06	15.00	13.3	7.9	16.6	38%	62%	0.98
1985	9.43	11.80	11.6	6.2	15.1	39%	61%	0.98
1986	8.97	12.00	10.5	6.3	13.4	41%	59%	0.70
1987	8.14	10.90	9.8	5.7	12.0	35%	65%	0.70
1988	9.48	11.30	11.3	6.5	13.4	31%	69%	0.70
1989	12.00	13.30	13.7	7.6	16.9	35%	65%	0.70
1990	12.78	12.30	14.5	7.1	18.3	34%	66%	0.70
Average 1947 to 1990			9.3	4.3	11.6			
Average 1970 to 1990			11.9	6.0	14.8			
Average 1980 to 1990			13.5	7.1	17.1			

Definitions:

1. Debt is all long term debt including convertible debentures (PMA)
2. Debt is valued at par (principal amount)
3. Equity includes preferred share capital
4. Prior to 1979, capital structure is estimated
5. The risk premium for the market portfolio was estimated to be 3.7%
6. Oil industry betas have been calculated for each five year period from 1956

Summary of the Investment Weighted Cost of Capital and Cost of Equity for the Canadian Oil Industry

	Cost of Capital			Cost of Equity		
	High	Low	Average	High	Low	Average
1970	10.4	8.8	9.4	13.2	11.0	11.8
1971	10.0	8.5	9.0	12.7	10	11.3
1972	9.7	8.3	8.8	12.2	10.2	10.9
1973	9.7	8.4	8.8	12.2	10.2	10.9
1974	10.1	8.8	9.2	12.6	10.7	11.4
1975	10.4	9.1	9.5	12.9	11.1	11.7
1976	10.9	9.7	10.1	13.7	11.9	12.5
1977	11.0	9.9	10.3	13.8	12.1	12.6
1978	11.5	10.4	10.8	14.4	12.8	13.3
1979	12.6	11.5	11.8	16.0	14.4	14.9
1980	13.8	12.7	13.0	17.4	15.8	16.3
1981	15.3	14.3	14.6	20.1	18.5	19.1
1982	15.7	14.6	15.0	20.5	18.9	19.5
1983	15.3	14.2	14.6	19.7	18.1	18.7
1984	15.1	14.1	14.5	19.5	17.9	18.6
1985	14.7	13.7	14.1	19.1	17.4	18.2
1986	14.4	13.3	13.8	18.6	17.0	17.7
1987	14.0	13.0	13.5	18.2	16.5	17.3
1988	13.8	12.8	13.3	17.8	16.2	16.9
1989	13.9	12.9	13.4	17.9	16.3	17.0
1990	14.1	13.1	13.5	18.1	16.5	17.2
Averages						
70 to 90	12.7	11.5	12.0	16.2	14.5	15.1
80 to 90	14.6	13.5	13.9	18.8	17.2	17.9

Note: 1. The high/low ranges are calculated using the Industry Beta plus/minus 1 standard deviation

Opportunity Cost of Capital
S&P Oil Composite Companies

Year	Risk Free Rate	Corporate Bond Yields	CAPM Industry Opportunity Cost of Capital	Implied Cost of Debt	Implied Cost of Equity	Capital Structure		Equity Beta
						Debt	Equity	
1981	14.10	14.4	17.7	7.5	22.4	32%	68%	0.75
1982	10.70	13.5	14.3	7.1	17.6	32%	68%	0.75
1983	8.60	12.4	12.3	6.5	14.7	30%	70%	0.75
1984	9.60	13.5	12.4	7.1	17.1	47%	53%	0.75
1985	7.50	12.1	10.2	6.3	13.9	49%	51%	0.75
1986	6.00	9.5	8.8	5.0	12.1	46%	54%	0.75
1987	5.80	10.2	8.8	5.4	11.4	42%	58%	0.75
1988	6.70	10.5	9.7	6.0	12.4	42%	58%	0.75
1989	8.10	10.0	11.1	5.8	15.0	42%	58%	0.75
1990	7.50	10.2	10.7	5.9	13.8	39%	61%	0.75
Average			11.6	6.3	15.1			

Definitions:

1. Debt is all long term debt including convertible debentures (PMA)
2. Debt is valued at par (principal amount)
3. Equity includes preferred share capital
4. The risk premium for the market portfolio was estimated to be 7.0%
5. Oil industry betas have been calculated from 1979
6. Excludes Drilling and Service companies

APPENDIX III

HISTORICAL FINANCIAL INFORMATION ON THE CANADIAN OIL AND GAS INDUSTRY

List of tables in Appendix III

Industry Financial Performance: Juniors

Industry Financial Performance: Seniors

Industry Financial Performance: Integrateds

Industry Financial Performance: Total Industry

PMA Sources and Uses of Funds: Juniors

PMA Sources and Uses of Funds: Seniors

PMA Sources and Uses of Funds: Integrateds

PMA Sources and Uses of Funds: Total Industry

The Components of Revenue

PMA Operating Costs

Upstream Industry Revenue Shares

Industry Financial Performance
Juniors

	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
UPSTREAM												
Production												
Liquids (MB/d)	NA	NA	NA	148	169	214	219	236	261	276	296	331
Gas (Bcf/d)	NA	NA	NA	1.38	1.37	1.68	1.77	1.77	1.97	2.43	2.79	3.08
BOE (MBOE/d)	NA	NA	NA	263	283	354	367	384	426	479	529	588
% of Total	NA	NA	NA	13.4%	14.3%	16.8%	17.0%	18.1%	19.0%	19.4%	21.5%	23.8%
Revenues	1403	1801	2134	2970	3546	4572	4712	3293	3276	3075	3712	4661
Cash Expenses												
Operating Costs	361	520	419	501	610	794	850	885	894	997	1166	1329
Interest Expense	(1)	(1)	367	608	603	640	673	693	507	420	449	474
Royalties	420	529	721	1011	1127	1477	1425	730	583	545	637	828
Other	0	0	0	85	75	96	110	108	83	89	96	85
Cash Taxes	44	32	20	-24	-48	18	22	-64	-74	-137	-100	-29
Total	825	1081	1527	2181	2367	3025	3080	2352	1993	1914	2248	2687
Cash Flow From Operations	578	720	607	789	1179	1547	1632	941	1283	1161	1464	1973
Non–Cash Items												
E&D Expense	62	89	87	97	62	42	54	72	68	87	118	134
Depreciation and Depletion	142	168	240	361	470	628	744	1020	847	999	1205	1423
Write-offs	15	31	26	59	131	142	165	333	12	93	66	71
Deferred Taxes	91	130	112	158	296	417	379	-39	89	-16	43	124
Other	0	0	0	5	2	2	-0	1	1	2	2	1
Total	310	418	465	680	961	1231	1342	1387	1017	1165	1434	1753
Net Income from Operations	268	302	142	109	218	316	290	-446	266	-4	30	220
Extraordinary Items	0	0	0	58	66	-1	-166	-356	13	390	-219	5
Net Income	268	302	142	167	284	315	124	-802	279	386	-189	225
Capital Expenditures	933	1303	1496	1384	1506	2160	2459	1667	1594	1920	1919	2483
Capital Employed	4091	6240	8434	11480	11757	14645	16334	14318	14139	14839	15563	15414
ROCE	10.7%	10.9%	6.1%	6.5%	7.7%	8.1%	5.5%	-3.1%	4.5%	4.2%	0.7%	4.0%
TOTAL OPERATIONS												
Revenues	2432	3427	3820	4576	5027	6234	6202	4692	4459	4188	4504	5534
Cash Expenses	1565	2151	2687	3506	3481	4236	4154	3433	2796	2672	2724	3220
Interest Expense	NA	NA	532	773	767	847	790	793	589	511	494	516
Non–Cash Items	479	774	876	1057	1394	1695	1833	1920	1271	1415	1568	1568
Deferred Taxes	NA	NA	273	165	345	443	385	-79	97	-14	22	135
Cash Flow From Operations	867	1276	1133	1070	1546	1998	2048	1259	1663	1516	1780	2314
Net Income	387	502	256	57	219	221	144	-1607	384	410	-56	363
Preferred Dividends	NA	NA	52	47	47	50	83	93	101	182	85	52
Balance Sheet Items												
Net PP&E	4585	6447	10610	13341	15010	15566	16286	14727	14229	14280	15237	16686
Total Assets	6443	8927	13630	16855	18495	19900	20481	18444	17710	17448	18190	19534
Current Liabilities	900	1282	1542	2110	2071	2230	2707	2341	1992	1471	1473	1740
Long-Term Debt	NA	3182	6035	7955	8650	8049	8009	6624	5403	4044	4217	4079
Accumulated Deferred Taxes	NA	808	1124	1335	1561	1894	2081	1669	1568	1539	1584	1727
Total Equity	2376	3122	4333	4542	5196	6665	6252	6534	7503	8895	9335	10370
Capital Expenditures	1342	2364	2973	2733	2473	2840	3213	2107	2263	2279	2179	2806
Capital Employed	5544	7644	11968	15314	11757	19234	18841	16814	17033	16939	17397	17794
Profitability Indicators												
ROCE	9.6%	9.2%	3.7%	1.2%	2.4%	2.1%	1.3%	-8.4%	2.9%	3.0%	0.3%	2.7%
ROE	16.3%	18.3%	6.9%	1.3%	4.5%	3.7%	2.2%	-25.1%	5.5%	5.0%	-0.6%	3.7%
Debt to Equity Ratio		1.02	1.39	1.75	1.66	1.21	1.28	1.01	0.72	0.45	0.45	0.39

Source: PMA

Industry Financial Performance
Seniors

	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
UPSTREAM												
Production												
Liquids (MB/d)	NA	NA	NA	607	621	765	776	721	765	806	759	735
Gas (Bcf/d)	NA	NA	NA	2.73	2.47	3.03	3.24	2.94	3.16	3.75	3.69	3.72
BOE (MBOE/d)	NA	NA	NA	835	826	1018	1046	967	1029	1119	1067	1045
% of Total	NA	NA	NA	42.6%	41.7%	48.1%	48.4%	45.6%	45.9%	45.4%	43.3%	42.3%
Revenues	6168	7702	7586	9278	10282	13236	14230	8389	8728	7634	7897	9101
Cash Expenses												
Operating Costs	1249	1666	1444	1656	1808	2268	2413	2492	2356	2698	2840	2937
Interest Expense	(1)	(1)	513	799	713	975	889	1011	1057	959	777	739
Royalties	1845	2248	2429	3165	3361	4179	4141	1785	1504	1185	1241	1426
Other	0	0	0	36	69	62	61	49	62	78	29	32
Cash Taxes	523	499	647	975	1292	1562	1890	362	648	85	74	510
Total	3617	4413	5033	6631	7243	9046	9394	5699	5627	5005	4961	5644
Cash Flow From Operations	2551	3289	2553	2647	3039	4190	4836	2690	3101	2629	2936	3457
Non–Cash Items												
E&D Expense	414	554	577	416	344	541	565	562	469	805	655	662
Depreciation and Depletion	452	556	424	645	795	997	1222	1535	1302	1514	1520	1534
Write-offs	102	159	122	135	699	284	145	488	558	121	274	443
Deferred Taxes	431	629	460	443	371	876	798	-12	4	-1	312	277
Other	0	0	0	5	4	8	21	18	16	19	21	17
Total	1399	1898	1583	1644	2213	2706	2751	2591	2349	2458	2782	2933
Net Income from Operations	1152	1391	970	1003	826	1484	2085	99	752	171	154	524
Extraordinary Items	0	0	0	42	10	9	37	-1538	119	-122	42	-39
Net Income	1152	1391	970	1045	836	1493	2122	-1439	871	49	196	485
Capital Expenditures	2523	3465	2880	2766	2736	3399	3916	2769	2335	2741	2187	2486
Capital Employed	10855	14362	14416	18174	18736	26827	28880	21602	23679	22760	22839	23017
ROCE	12.1%	12.1%	11.8%	11.7%	8.6%	12.6%	12.2%	-3.6%	6.3%	2.6%	4.2%	5.2%
TOTAL OPERATIONS												
Revenues	11767	14482	9195	12882	12471	19530	19806	10246	10294	9534	10095	11387
Cash Expenses	8260	10262	6309	10097	9153	14654	14483	7304	6774	6459	6545	7447
Interest Expense	NA	NA	805	1225	1019	1363	1190	1472	1236	1117	916	835
Non–Cash Items	1878	2284	1789	2164	3017	3175	3255	2882	2612	2871	3341	3285
Deferred Taxes	NA	NA	471	339	339	751	738	-221	16	-11	317	259
Cash Flow From Operations	3507	4220	2886	2785	3318	4876	5323	2942	3520	3075	3550	3940
Net Income	1630	1936	1097	641	311	1714	2114	-2176	1028	118	267	628
Preferred Dividends	NA	NA	47	47	65	65	58	100	57	196	117	136
Balance Sheet Items												
Net PP&E	12884	16599	18427	20549	19901	23898	26319	24127	25564	25191	25007	24907
Total Assets	19151	23914	25406	29182	28708	39585	40096	33130	32361	30297	30269	31363
Current Liabilities	3058	3732	3091	6523	6321	5377	6015	3096	3653	3058	3160	3672
Long-Term Debt	NA	4832	8185	6357	5800	11861	12844	13973	11935	8950	8576	9065
Accumulated Deferred Taxes	NA	NA	2337	2825	3148	4641	5034	4238	4207	3835	4066	4325
Total Equity	7903	9599	8381	10092	10129	13690	14279	9846	10690	12335	12236	12171
Capital Expenditures	3333	4417	4124	3709	3232	4108	4755	3130	2775	3320	2687	3070
Capital Employed	16092	20181	21385	22233	22362	33894	36386	29046	27936	27589	27134	27691
Profitability Indicators												
ROCE	14.6%	11.3%	15.6%	16.0%	13.6%	15.9%	17.9%	-7.8%	10.3%	4.3%	7.0%	8.4%
ROE	20.6%	22.1%	12.2%	6.9%	3.1%	14.4%	15.1%	-18.0%	10.0%	1.0%	2.2%	5.1%
Debt to Equity Ratio		0.50	0.98	0.63	0.57	0.87	0.90	1.42	1.12	0.73	0.70	0.74

Source: PMA

Industry Financial Performance
Integrateds

	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
UPSTREAM												
Production												
Liquids (MB/d)	NA	NA	NA	715	739	629	626	656	654	709	690	660
Gas (Bcf/d)	NA	NA	NA	1.74	1.62	1.36	1.44	1.35	1.61	1.86	2.13	2.10
BOE (MBOE/d)	NA	NA	NA	860	873	742	747	769	788	865	867	835
% of Total	NA	NA	NA	43.9%	44.0%	35.1%	34.6%	36.3%	35.1%	35.1%	35.2%	33.8%
Revenues	5144	6614	7483	8792	9988	8753	9019	5308	5901	5053	5899	6802
Cash Expenses												
Operating Costs	970	1260	1761	1834	1763	1624	1987	1841	1817	2097	2365	2435
Interest Expense	(1)	(1)	114	160	112	41	12	4	80	28	80	41
Royalties	1678	2155	2769	3395	3610	3021	2785	1081	962	807	855	957
Other	0	0	0	77	35	34	65	68	43	38	61	65
Cash Taxes	474	507	748	906	1382	1331	1118	476	549	77	394	651
Total	3122	3922	5392	6372	6902	6051	5967	3470	3451	3047	3755	4149
Cash Flow From Operations	2022	2692	2091	2420	3086	2702	3052	1838	2450	2006	2144	2653
Non-Cash Items												
E&D Expense	534	748	805	469	416	503	415	494	329	464	325	359
Depreciation and Depletion	194	226	373	361	506	515	608	572	644	695	748	610
Write-offs	41	121	143	225	215	179	217	246	303	329	313	490
Deferred Taxes	239	385	236	431	535	433	546	83	279	112	87	118
Other	0	0	0	46	29	17	15	19	11	16	19	28
Total	1008	1480	1557	1532	1701	1647	1801	1414	1566	1616	1492	1605
Net Income from Operations	1014	1212	534	888	1385	1055	1251	424	884	390	652	1048
Extraordinary Items	0	0	0	0	0	0	-205	-75	-39	-39	0	0
Net Income	1014	1212	534	888	1385	1055	1046	349	845	351	652	1048
Capital Expenditures	1623	2106	2460	2318	2544	2395	2910	1837	1600	2123	1578	1456
Capital Employed	5385	6293	11598	12429	11711	10926	11466	10718	11502	14568	16809	15926
ROCE	24.2%	27.8%	9.3%	11.7%	16.4%	13.3%	14.3%	3.9%	10.5%	3.7%	5.0%	7.3%
TOTAL OPERATIONS												
Revenues	19648	23856	36977	36987	41602	36829	39705	32682	34406	33278	36105	41465
Cash Expenses	16661	19744	32865	33536	37850	32967	35608	28920	30176	28880	32451	37810
Interest Expense	NA	NA	453	667	710	590	476	496	464	442	1129	1113
Non-Cash Items	1385	1811	2350	2417	2738	2529	2549	2479	2452	2695	2409	2225
Deferred Taxes	NA	NA	496	780	703	705	536	312	378	263	140	-143
Cash Flow From Operations	2987	4112	4112	3451	3752	3862	4097	3762	4230	4398	3654	3655
Net Income	1602	2300	1762	1078	1004	1536	968	981	1832	1651	1123	1429
Preferred Dividends	NA	NA	46	58	42	36	140	113	188	47	84	96
Balance Sheet Items												
Net PP&E	8534	9768	18375	19194	21977	19902	21183	21384	22278	26367	29045	28605
Total Assets	16033	19553	33022	33394	37378	34564	35256	32445	34337	38338	40337	41792
Current Liabilities	3438	3875	6709	6434	7418	6990	7193	4872	5409	6852	6732	7982
Long-Term Debt	NA	1489	4687	4501	4942	3415	3584	3384	2920	5396	8638	7811
Accumulated Deferred Taxes	NA	NA	4048	4331	5000	4938	4857	4766	5177	5795	5827	5515
Total Equity	8641	11360	16393	16815	18661	17783	18470	18301	19634	19029	17795	18310
Capital Expenditures	2119	2773	4760	5272	4641	3505	4031	2705	2539	3543	3057	2770
Capital Employed	12595	15679	26191	28205	29915	27713	28193	27575	28726	31480	34355	33810
Profitability Indicators												
ROCE	14.2%	17.0%	11.1%	7.1%	6.1%	7.9%	5.4%	4.6%	8.0%	6.4%	4.0%	3.8%
ROE	18.5%	23.0%	12.7%	6.5%	5.7%	8.4%	5.3%	5.3%	9.7%	8.5%	6.1%	7.9%
Debt to Equity Ratio		0.13	0.29	0.27	0.26	0.19	0.19	0.18	0.15	0.28	0.49	0.43

Source: PMA

Industry Financial Performance
Total Industry

	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
UPSTREAM												
Production												
Liquids (MB/d)	NA	1632	1494	1470	1528	1608	1621	1613	1681	1791	1745	1726
Gas (Bcf/d)	NA	5.78	5.69	5.85	5.46	6.07	6.45	6.07	6.74	8.04	8.61	8.91
BOE (MBOE/d)	NA	2114	1968	1958	1983	2114	2159	2119	2243	2462	2463	2468
Revenues	12715	16117	17203	21040	23816	26561	27961	16990	17905	15762	17508	20564
Cash Expenses												
Operating Costs	2580	3446	3624	3991	4181	4686	5250	5218	5067	5792	6371	6701
Interest Expense	(1)	450	994	1567	1428	1656	1574	1708	1644	1407	1306	1254
Royalties	3943	4932	5919	7571	8098	8677	8351	3596	3049	2537	2733	3211
Other	0	0	0	198	179	192	236	225	188	205	186	182
Cash Taxes	1041	1038	1415	1857	2626	2911	3030	774	1123	25	368	1132
Total	7564	9416	11952	15184	16512	18122	18441	11521	11071	9966	10964	12480
Cash Flow From Operations	5151	6701	5251	5856	7304	8439	9520	5469	6834	5796	6544	8083
Non-Cash Items												
E&D Expense	1010	1391	1469	982	822	1086	1034	1128	866	1356	1098	1155
Depreciation and Depletion	788	950	1037	1367	1771	2140	2574	3127	2793	3208	3473	3567
Write-offs	158	311	291	419	1045	605	527	1067	873	543	653	1004
Deferred Taxes	761	1144	808	1032	1202	1726	1723	32	372	95	442	519
Other	0	0	0	56	35	27	36	38	28	37	42	46
Total	2717	3796	3605	3856	4875	5584	5894	5392	4932	5239	5708	6291
Net Income from Operations	2434	2905	1646	2000	2429	2855	3626	77	1902	557	836	1792
Extraordinary Items	0	0	0	100	76	8	-334	-1969	93	229	-177	-34
Net Income	2434	2905	1646	2100	2505	2863	3292	-1892	1995	786	659	1758
Capital Expenditures	5079	6874	6836	6468	6786	7954	9285	6273	5529	6784	5684	6425
Total Equity	11237	14887	16839	20128	22400	24720	26499	22026	25316	27631	27552	28004
Capital Employed	20331	26895	34448	42083	42204	52398	56680	46638	49320	52167	55211	54357
ROE	21.7%	22.2%	10.4%	11.4%	11.8%	12.2%	12.9%	-7.8%	8.4%	3.0%	2.4%	6.3%
ROCE	17.1%	18.1%	9.7%	10.3%	10.6%	11.5%	10.7%	-1.9%	6.7%	3.2%	3.3%	5.4%
TOTAL OPERATIONS												
Revenues	33847	41765	49992	54445	59100	62593	65713	47620	49159	47000	50704	58386
Cash Expenses	26486	32157	41861	47139	50484	51857	54245	39657	39746	38011	41720	48477
Interest Expense	780	800	1790	2665	2496	2800	2456	2761	2289	2070	2539	2464
Non-Cash Items	3742	4869	5015	5638	7149	7399	7637	7281	6335	6981	7318	7078
Deferred Taxes	1189	1512	1240	1284	1387	1899	1659	12	491	238	479	251
Cash Flow From Operations	7361	9608	8131	7306	8616	10736	11468	7963	9413	8989	8984	9909
Net Income	3619	4738	3115	1776	1534	3471	3226	-2802	3244	2179	1334	2420
Preferred Dividends	NA	NA	145	152	154	151	281	306	346	425	286	284
Balance Sheet Items												
Net PP&E	26003	32814	47412	53084	56888	59366	63788	60238	62071	65838	69289	70198
Total Assets	41627	52394	72058	79431	84581	94049	95833	84019	84408	86083	88796	92689
Current Liabilities	7396	8889	11342	15067	15810	14597	15915	10309	11054	11381	11365	13394
Long-Term Debt	9372	9504	18907	18813	19392	23325	24437	23981	20258	18390	21431	20955
Accumulated Deferred Taxes	5939	6685	7509	8491	9709	11473	11972	10673	10952	11169	11477	11567
Total Equity	18920	24081	29107	31449	33986	38138	39001	34681	37827	40259	39366	40851
Capital Expenditures	6794	9554	11857	11714	10346	10453	11999	7942	7577	9142	7923	8646
Capital Employed	34231	43504	59544	65752	64034	80841	83420	73435	73695	76008	78886	79295
Profitability Indicators												
ROCE	15.8%	17.2%	10.3%	7.1%	6.5%	9.4%	7.5%	-1.7%	6.7%	4.7%	4.1%	5.0%
ROE	19.1%	22.0%	11.7%	5.9%	4.7%	9.6%	8.4%	-7.6%	8.9%	5.6%	3.4%	6.0%
ROCE Downstream	12.6%	15.6%	11.1%	2.1%	-1.0%	5.5%	1.2%	-1.4%	6.7%	7.8%	5.7%	4.2%
ROE Downstream	15.4%	21.7%	13.7%	-2.7%	-8.5%	4.9%	-0.5%	-7.2%	9.9%	11.1%	5.5%	5.4%
Debt/Equity Ratio	0.50	0.39	0.65	0.60	0.57	0.61	0.63	0.69	0.54	0.46	0.54	0.51

Source: PMA

PMA Sources and Uses of Funds
Juniors

	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
Sources of Funds												
Cash Flow	867	1276	1133	1070	1546	1998	2048	1259	1663	1516	1780	2314
Increase in L.T. Debt	360	1158	2782	2246	896	1070	1038	341	600	522	913	639
Equity	329	380	686	763	691	1085	846	1851	1195	1361	1347	819
Incentives	NA	NA	135	243	315	508	461	327	201	187	105	15
Other Sources	327	270	751	764	678	692	1725	1506	1373	1907	1250	999
Working Capital Decrease	113	421	320	426	463	522	709	350	473	481	512	586
Total Sources of Funds	1996	3505	5807	5512	4589	5875	6827	5634	5505	5974	5907	5372
Uses of Funds												
Capital Expenditures												
Exploration	608	760	764	637	821	1281	1399	927	904	979	918	1141
Development	179	285	409	394	386	485	534	346	341	487	415	488
Production	144	232	285	340	295	383	442	340	344	449	530	642
Oil Sands	2	26	38	13	4	11	84	54	5	5	56	212
Total Upstream	933	1303	1496	1384	1506	2160	2459	1667	1594	1920	1919	2483
Total Downstream	0	40	191	201	113	9	21	5	299	8	7	3
Foreign	347	705	951	758	575	439	547	399	298	259	213	238
Other	62	316	335	390	279	232	186	36	72	92	40	82
Total	1342	2364	2973	2733	2473	2840	3213	2107	2263	2279	2179	2806
Dividends	84	115	109	91	97	180	265	142	162	240	156	152
Reduction in Equity	24	58	34	81	150	109	239	89	181	41	159	49
Decrease in L.T. Debt	128	176	229	238	474	1020	921	1640	959	1119	595	812
Other Uses	154	509	1979	1979	737	1292	1827	1170	1280	1658	2369	1148
Working Capital Increase	264	283	483	390	659	432	361	487	660	637	449	404
Total Uses of Funds	1996	3505	5807	5512	4590	5873	6826	5635	5505	5974	5907	5371

PMA Sources and Uses of Funds
Seniors

	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
Sources of Funds												
Cash Flow	3507	4220	2886	2785	3318	4876	5323	2942	3520	3075	3550	3940
Increase in L.T. Debt	962	1605	4152	275	349	3121	572	1019	251	798	598	1304
Equity	671	188	909	661	452	63	248	539	317	410	284	170
Incentives	NA	NA	377	804	686	796	779	444	187	139	89	44
Other Sources	533	356	287	1363	1789	3273	1333	2802	5343	2126	1399	1055
Working Capital Decrease	1044	221	373	3242	635	329	782	2208	802	2120	287	230
Total Sources of Funds	6717	6590	8984	9130	7229	12458	9037	9954	10420	8668	6207	6743
Uses of Funds												
Capital Expenditures												
Exploration	1564	2137	1697	1803	1923	2336	2286	1455	1171	1272	1005	954
Development	402	547	479	359	358	413	658	421	446	468	252	365
Production	411	598	607	531	358	510	679	685	517	713	793	888
Oil Sands	146	183	97	73	97	140	293	209	201	288	137	279
Total Upstream	2523	3465	2880	2766	2736	3399	3916	2769	2335	2741	2187	2486
Total Downstream	204	261	195	143	40	183	162	109	99	85	43	43
Foreign	377	473	672	343	153	189	476	149	178	304	245	327
Other	229	218	377	457	303	337	201	103	163	190	212	214
Total	3333	4417	4124	3709	3232	4108	4755	3130	2775	3320	2687	3070
Dividends	263	285	307	294	437	507	783	1700	554	499	436	811
Reduction of Equity	184	102	232	389	284	43	195	196	81	341	128	43
Decrease in L.T. Debt	161	271	19	2186	833	759	627	522	2606	1336	937	810
Other Uses	2324	1092	3271	2106	1528	3606	1813	4203	3451	2838	1387	1685
Working Capital Increase	451	423	1031	446	916	3436	864	202	954	335	633	324
Total Uses of Funds	6716	6590	8984	9130	7230	12459	9037	9953	10421	8669	6208	6743

PMA Sources and Uses of Funds
Integrateds

	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
Sources of Funds												
Cash Flow	2987	4112	4112	3451	3752	3862	4097	3762	4230	4398	3654	3655
Increase in L.T. Debt	470	14	2601	1012	469	70	449	540	45	931	3833	660
Equity	14	959	521	1784	1019	667	865	24	284	585	1405	383
Incentives	NA	NA	310	419	665	577	620	368	119	93	28	36
Other Sources	445	175	340	1010	449	1086	1028	546	945	474	1253	2494
Working Capital Decrease	0	0	498	702	418	81	1324	775	748	2200	791	412
Total Sources of Funds	3916	5260	8382	8378	6772	6343	8383	6015	6371	8681	10964	7640
Uses of Funds												
Capital Expenditures												
Exploration	983	1215	1334	1165	1537	1362	1245	891	601	745	607	539
Development	228	193	201	227	218	228	325	281	270	322	132	130
Production	196	258	528	629	464	372	586	327	387	505	612	548
Oil Sands	216	440	397	297	325	433	754	338	342	551	227	239
Total Upstream	1623	2106	2460	2318	2544	2395	2910	1837	1600	2123	1578	1456
Total Downstream	314	448	1566	2142	1550	863	758	682	811	1235	1224	1071
Foreign	2	2	141	53	28	48	59	22	20	49	76	89
Other	180	217	593	759	519	199	304	164	108	136	179	154
Total	2119	2773	4760	5272	4641	3505	4031	2705	2539	3543	3057	2770
Dividends	404	540	704	735	723	661	742	731	795	1727	771	703
Reduction of Equity	2	0	43	142	16	13	93	168	194	1032	544	600
Decrease in L.T. Debt	50	167	292	1137	224	795	336	768	1010	227	468	1504
Other Uses	211	27	1809	676	852	735	2269	1410	1404	1655	5671	1002
Working Capital Increase	1129	1752	774	414	315	635	911	231	427	499	454	1061
Total Uses of Funds	3915	5259	8382	8376	6771	6344	8382	6013	6369	8683	10965	7640

PMA Sources and Uses of Funds
Total Industry

	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
Sources of Funds												
Cash Flow	7361	9608	8131	7306	8616	10736	11468	7963	9413	8989	8984	9909
Increase in L.T. Debt	1792	2777	9535	3533	1714	4261	2059	1900	896	2251	5344	2603
Equity	1014	1527	2116	3208	2162	1815	1959	2414	1796	2356	3036	1372
Incentives	NA	NA	822	1466	1666	1881	1860	1139	507	419	222	95
Other Sources	1305	801	1378	3137	2916	5051	4086	4854	7661	4507	3902	4548
Working Capital Decrease	1157	642	1191	4370	1516	932	2815	3333	2023	4801	1590	1228
Total Sources of Funds	12629	15355	23173	23020	18590	24676	24247	21603	22296	23323	23078	19755
Uses of Funds												
Capital Expenditures												
Exploration	2732	4112	3795	3605	4281	4979	4930	3273	2676	2996	2530	2634
Development	799	1025	1089	980	962	1126	1517	1048	1057	1277	799	983
Production	746	1088	1420	1500	1117	1265	1707	1352	1248	1667	1935	2078
Oil Sands	364	649	532	383	426	584	1131	601	548	844	420	730
Frontier	439	761	1178	1798	2423	2464	1977	1243	449	542	449	328
Total Upstream	5079	6874	6836	6468	6786	7954	9285	6273	5529	6784	5684	6425
Total Downstream	518	749	1952	2486	1703	1055	941	796	1209	1328	1274	1117
Foreign	726	1180	1764	1154	756	676	1082	570	496	612	534	654
Other	471	751	1305	1606	1101	768	691	303	343	418	431	450
Total	6794	9554	11857	11714	10346	10453	11999	7942	7577	9142	7923	8646
Dividends	751	940	1120	1120	1257	1348	1790	2573	1511	2466	1363	1666
Reduction of Equity	210	160	309	612	450	165	527	453	456	1414	831	692
Decrease in L.T. Debt	339	614	540	3561	1531	2574	1884	2930	4575	2682	2000	3126
Other Uses	2689	1628	7059	4761	3117	5633	5909	6783	6135	6151	9427	3835
Working Capital Increase	1844	2458	2288	1250	1890	4503	2136	920	2041	1471	1536	1789
Total Uses of Funds	12627	15354	23173	23018	18591	24676	24245	21601	22295	23326	23080	19754

The Components of Revenue
($/BOE)

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
Revenue	20.89	23.95	29.44	32.90	34.42	35.48	21.97	21.87	17.54	19.48	22.83
Cash Expenses											
Operating Costs	4.47	5.04	5.59	5.78	6.07	6.66	6.75	6.19	6.45	7.09	7.44
% of Revenue	21.4%	21.1%	19.0%	17.6%	17.6%	18.8%	30.7%	28.3%	36.7%	36.4%	32.6%
Interest Expense	0.58	1.38	2.19	1.97	2.15	2.00	2.21	2.01	1.57	1.45	1.39
% of Revenue	2.8%	5.8%	7.4%	6.0%	6.2%	5.6%	10.1%	9.2%	8.9%	7.5%	6.1%
Royalties	6.39	8.24	10.60	11.19	11.24	10.60	4.65	3.72	2.82	3.04	3.56
% of Revenue	30.6%	34.4%	36.0%	34.0%	32.7%	29.9%	21.2%	17.0%	16.1%	15.6%	15.6%
Other	0.00	0.00	0.28	0.25	0.25	0.30	0.29	0.23	0.23	0.21	0.20
% of Revenue	0.0%	0.0%	0.9%	0.8%	0.7%	0.8%	1.3%	1.0%	1.3%	1.1%	0.9%
Cash Taxes	1.35	1.97	2.60	3.63	3.77	3.84	1.00	1.37	0.03	0.41	1.26
% of Revenue	6.4%	8.2%	8.8%	11.0%	11.0%	10.8%	4.6%	6.3%	0.2%	2.1%	5.5%
Total	12.21	16.64	21.25	22.81	23.48	23.40	14.90	13.52	11.09	12.20	13.85
% of Revenue	58.4%	69.5%	72.2%	69.3%	68.2%	66.0%	67.8%	61.8%	63.2%	62.6%	60.7%
Cash Flow From Operations	8.69	7.31	8.20	10.09	10.94	12.08	7.07	8.35	6.45	7.28	8.97
% of Revenue	41.6%	30.5%	27.8%	30.7%	31.8%	34.0%	32.2%	38.2%	36.8%	37.4%	39.3%
Non–Cash Items											
E&D Expense	1.80	2.04	1.37	1.14	1.41	1.31	1.46	1.06	1.51	1.22	1.28
% of Revenue	8.6%	8.5%	4.7%	3.5%	4.1%	3.7%	6.6%	4.8%	8.6%	6.3%	5.6%
Depreciation and Depletion	1.23	1.44	1.91	2.45	2.77	3.27	4.04	3.41	3.57	3.86	3.96
% of Revenue	5.9%	6.0%	6.5%	7.4%	8.1%	9.2%	18.4%	15.6%	20.4%	19.8%	17.3%
Write-offs	0.40	0.41	0.59	1.44	0.78	0.67	1.38	1.07	0.60	0.73	1.11
% of Revenue	1.9%	1.7%	2.0%	4.4%	2.3%	1.9%	6.3%	4.9%	3.4%	3.7%	4.9%
Deferred Taxes	1.48	1.12	1.44	1.66	2.24	2.19	0.04	0.45	0.11	0.49	0.58
% of Revenue	7.1%	4.7%	4.9%	5.0%	6.5%	6.2%	0.2%	2.1%	0.6%	2.5%	2.5%
Other	0.00	0.00	0.08	0.05	0.03	0.05	0.05	0.03	0.04	0.05	0.05
% of Revenue	0.0%	0.0%	0.3%	0.1%	0.1%	0.1%	0.2%	0.2%	0.2%	0.2%	0.2%
Total	4.92	5.02	5.40	6.74	7.24	7.48	6.97	6.02	5.83	6.35	6.98
% of Revenue	23.6%	21.0%	18.3%	20.5%	21.0%	21.1%	31.7%	27.5%	33.2%	32.6%	30.6%
Net Income from Operations	3.77	2.29	2.80	3.36	3.70	4.60	0.10	2.32	0.62	0.93	1.99
% of Revenue	18.0%	9.6%	9.5%	10.2%	10.7%	13.0%	0.5%	10.6%	3.5%	4.8%	8.7%
Extraordinary Items	0.00	0.00	0.14	0.10	0.01	-0.42	-2.55	0.11	0.25	-0.20	-0.04
Net Income	3.77	2.29	2.94	3.46	3.71	4.18	-2.45	2.44	0.87	0.73	1.95
% of Revenue	18.0%	9.6%	10.0%	10.5%	10.8%	11.8%	-11.1%	11.1%	5.0%	3.8%	8.5%

PMA Operating Costs

	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
Total Operating Costs	2580	3446	3624	3991	4181	4686	5250	5218	5067	5792	6371	6701
$/Boe	NA	NA	NA	5.59	5.78	6.07	6.66	6.75	6.19	6.45	7.09	7.44
G&A	NA	NA	880	1105	1106	1203	1324	1340	1236	1325	1490	1486
$/Boe	NA	NA	NA	1.55	1.53	1.56	1.68	1.73	1.51	1.47	1.66	1.65
Conventional	NA	NA	1946	1968	2118	2468	2782	2767	2735	3175	3494	3779
$/Boe	NA	NA	NA	2.95	3.21	3.45	3.90	4.08	3.79	4.05	4.47	4.83
Oil Sands	NA	NA	799	918	958	1015	1144	1112	1096	1292	1387	1437
$/Boe	NA	NA	NA	19.33	14.82	17.73	15.19	11.71	11.23	11.28	11.90	12.06

Source: PMA

Upstream Industry Revenue Shares

	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
Industry												
Cash Flow Before Interest	5676	7901	6245	7423	8732	10095	11094	7177	8478	7203	7850	9337
PIP and other Incentive Grants	0	0	920	1600	1760	1920	1760	1010	292	266	139	0
Land Payments to Crown	-1101	-1003	-830	-530	-710	-940	-1330	-490	-793	-659	-486	-842
Total	4575	6898	6335	8493	9782	11075	11524	7697	7977	6810	7503	8495
% Share	45.1%	52.2%	47.4%	50.9%	51.1%	51.7%	52.1%	66.7%	65.2%	72.0%	70.4%	64.0%
Provincial												
Royalties and Freehold Tax	3431	4281	4620	5340	5700	5950	5730	3140	2628	2222	2436	2810
Land Payments	1089	982	820	520	700	930	1320	490	793	659	486	842
Corporate Income Tax	129	105	196	171	385	605	549	16	151	-160	-40	228
PIP and Other Incentives Paid	0	0	-410	-520	-410	-410	-500	-340	0	0	0	0
Total	4649	5368	5226	5511	6375	7075	7099	3306	3572	2721	2882	3880
% Share	45.8%	40.6%	39.1%	33.0%	33.3%	33.1%	32.1%	28.6%	29.2%	28.8%	27.1%	29.2%
Federal Share												
PGRT	0	0	1060	2070	2100	2450	2270	452	0	0	0	0
Corporate Income Tax	911	934	1231	1687	2242	2303	2482	757	970	191	408	903
Land Payments and Royalties	12	21	10	10	10	10	10	0	0	0	0	0
PIP and Other Incentives Paid	0	0	-510	-1080	-1350	-1510	-1260	-670	-292	-266	-139	
Total	923	955	1791	2687	3002	3253	3502	539	678	-75	269	903
% Share	9.1%	7.2%	13.4%	16.1%	15.7%	15.2%	15.8%	4.7%	5.5%	-0.8%	2.5%	6.8%

Source: PMA

APPENDIX IV

SELECTED FINANCIAL INFORMATION ON OTHER CANADIAN INDUSTRIES

List of tables in Appendix IV

Total Industries - Excluding Petroleum

Total Manufacturing

Non-Crown Utilities

Summary of Canadian Oil Industry Profitability

Total Industries – Excluding Petroleum

	Total Assets ($MM)	Total Current Liabilities ($MM)	Total Shareholder Equity ($MM)	Net Income ($MM)	Interest on Long-term Debt ($MM)	Deferred Income Taxes ($MM)	Return on Average Capital Employed	Return on Equity
1970	91,744	21,830	45,115	3,749	1,228	280	6.7%	8.3%
1971	98,452	23,595	48,179	4,429	1,315	282	7.5%	9.5%
1972	105,375	25,545	51,205	5,256	1,285	446	8.2%	10.6%
1973	117,919	30,934	57,108	7,526	1,440	774	10.9%	13.9%
1974	138,232	41,797	63,318	9,226	1,760	1,195	12.4%	15.3%
1975	150,942	44,269	69,015	8,694	2,084	1,111	10.7%	13.1%
1976	163,795	47,178	74,801	8,478	2,472	1,052	9.7%	11.8%
1977	171,954	42,155	71,589	8,168	3,232	1,341	9.1%	11.2%
1978	197,643	49,182	80,845	8,544	3,761	1,854	8.9%	11.2%
1979	198,358	56,234	78,285	12,304	4,720	1,799	11.7%	15.7%
1980	231,518	65,467	90,928	13,017	5,070	1,891	11.4%	15.4%
1981	270,496	76,677	101,652	11,178	7,078	916	8.8%	11.6%
1982	287,263	75,877	104,341	5,890	9,095	55	5.3%	5.7%
1983	306,610	79,029	115,390	10,032	8,593	686	6.9%	9.1%
1984	327,144	85,936	125,668	13,307	9,660	111	7.9%	11.0%
1985	360,984	92,721	140,293	13,604	9,958	861	7.7%	10.2%
1986	393,071	97,644	154,999	15,174	10,212	1,669	7.9%	10.3%
1987	429,294	108,405	170,290	19,037	10,560	3,918	9.2%	11.7%
1988	480,125	122,515	185,563	24,920	11,318	3,337	10.2%	14.0%
1989	521,888	130,873	199,069	21,436	12,923	2,409	8.4%	11.1%
1990	544,814	133,946	205,924	14,260	14,456	868	5.8%	7.0%

Source: Statistics Canada, PMA

Total Manufacturing

	Total Assets ($MM)	Total Current Liabilities ($MM)	Total Shareholder Equity ($MM)	Net Income ($MM)	Interest on Long-term Debt ($MM)	Deferred Income Taxes ($MM)	Return on Average Capital Employed	Return on Equity
1970	42,791	10,404	21,730	1,583	497	100	6.0%	7.3%
1971	45,019	11,141	22,845	2,134	509	105	7.6%	9.6%
1972	47,620	12,030	24,236	2,622	458	194	8.8%	11.1%
1973	52,658	14,289	26,930	3,727	514	441	12.0%	14.6%
1974	62,649	19,580	30,314	4,848	616	694	14.4%	16.9%
1975	68,339	20,265	33,243	4,327	790	611	11.7%	13.6%
1976	73,900	21,851	35,669	4,217	961	481	10.4%	12.2%
1977	71,695	19,577	33,834	3,781	991	618	9.4%	10.9%
1978	82,401	22,844	39,159	5,009	1,086	680	11.2%	13.7%
1979	99,635	29,568	46,591	7,679	1,316	1,301	14.9%	17.9%
1980	116,912	33,424	55,203	8,817	1,608	1,485	14.5%	17.3%
1981	138,426	37,777	62,302	6,920	2,550	1,203	10.3%	11.8%
1982	143,262	37,214	63,964	2,030	3,502	295	4.0%	3.2%
1983	151,634	39,288	68,811	5,907	3,216	625	7.5%	8.9%
1984	165,292	43,658	77,039	8,881	3,452	534	9.6%	12.2%
1985	176,430	45,205	83,509	8,329	3,166	749	8.5%	10.4%
1986	182,258	44,478	89,836	8,649	3,154	996	8.4%	10.0%
1987	201,642	50,251	97,942	12,383	2,956	3,069	11.8%	13.2%
1988	222,691	54,528	104,128	16,227	3,202	2,131	12.6%	16.1%
1989	241,181	58,829	106,999	11,694	4,321	1,446	8.9%	11.1%
1990	249,858	60,319	110,689	7,296	4,885	313	5.6%	6.7%

Source: Statistics Canada

Non-Crown Utilities

	Total Assets ($MM)	Total Current Liabilities ($MM)	Total Shareholder Equity ($MM)	Net Income ($MM)	Interest on Long-term Debt ($MM)	Deferred Income Taxes ($MM)	Return on Average Capital Employed	Return on Equity
1970	3,122	350	1,095	111	93	15	6.3%	10.1%
1971	3,432	354	1,125	120	108	15	6.5%	10.8%
1972	3,747	314	1,169	134	136	21	7.0%	11.7%
1973	4,011	401	1,245	142	150	21	6.9%	11.8%
1974	3,701	515	1,334	139	150	18	6.9%	10.8%
1975	4,184	722	1,518	171	158	18	8.2%	12.0%
1976	4,754	703	1,815	217	188	14	8.8%	13.0%
1977	5,422	801	2,048	178	175	0	6.2%	9.2%
1978	5,841	908	2,322	245	195	0	7.3%	11.2%
1979	7,315	1,536	2,956	260	215	0	7.0%	9.9%
1980	9,671	1,920	4,477	375	234	0	7.4%	10.1%
1981	9,016	1,884	3,425	448	318	0	8.3%	11.3%
1982	10.629	2.303	4,029	468	414	0	8.9%	12.6%
1983	11,658	2,219	4,758	600	450	0	9.4%	13.7%
1984	12.234	2.179	5,094	638	483	0	9.1%	13.0%
1985	14.451	2.753	5,644	733	554	0	9.4%	13.7%
1986	14,391	2,653	5,730	665	572	0	8.2%	11.7%
1987	15,314	2.805	6,135	777	577	0	8.9%	13.1%
1988	17,489	3,706	6,459	737	638	0	8.4%	11.7%
1989	18,097	3,878	6,763	815	708	0	8.7%	12.3%
1990	18,818	3,707	6,845	932	740	0	9.3%	13.7%

Source: Statistics Canada

Summary of Canadian Oil Industry Profitability From 1979 to 1990

	Return on Equity			Return on Capital Employed		
	Upstream	Downstream	Total	Upstream	Downstream	Total
1979	21.7%	15.4%	19.1%	17.1%	12.6%	15.8%
1980	22.2%	21.7%	22.0%	18.1%	15.6%	17.2%
1981	10.4%	13.7%	11.7%	9.7%	11.1%	10.3%
1982	11.4%	-2.7%	5.9%	10.3%	2.1%	7.1%
1983	11.8%	-8.5%	4.7%	10.6%	-1.0%	6.5%
1984	12.2%	4.9%	9.6%	11.5%	5.5%	9.4%
1985	12.9%	-0.5%	8.4%	10.7%	1.2%	7.5%
1986	-7.8%	-7.2%	-7.6%	-1.9%	-1.4%	-1.7%
1987	8.4%	9.9%	8.9%	6.7%	6.7%	6.7%
1988	3.0%	11.1%	5.6%	3.2%	7.8%	4.7%
1989	2.4%	5.5%	3.4%	3.3%	5.7%	4.1%
1990	6.3%	5.4%	6.0%	5.4%	4.2%	5.0%
Averages						
79 to 90	9.6%	5.7%	8.1%	8.7%	5.8%	7.7%
81 to 90	7.1%	3.1%	5.7%	7.0%	4.2%	6.0%
86 to 90	2.5%	4.9%	3.3%	3.3%	4.6%	3.7%

Note: 1. Upstream & downstream equity has been estimated by the interest portion of long term debt reported to the PMA

2. Calculated ROCE's do not correspond to the PMA figures due to PowerWest's handling of depletion

Source: PMA, PowerWest

APPENDIX V — FINDING AND DEVELOPMENT COSTS-- METHODOLOGY AND CORPORATE RESULTS

FINDING AND DEVELOPMENT COSTS - METHODOLOGY

The methodology we have employed in calculating finding and development (F&D) costs is simple, consistent, and easy to understand. Our intent is for all companies to be evaluated on a common basis allowing meaningful comparison of F&D results. We calculated our results using publicly available information with additional details provided by the companies themselves.

Finding and development costs are the total direct costs associated with discovering and developing oil and gas reserves for commercial production, per barrel of oil equivalent (BOE). These costs include land acquisition, seismic, drilling and completion, and production facilities. Although the concept of finding and development costs is simple, in practice there are difficulties in accurately estimating the capital associated with discovering and developing reserves, as well as determining the appropriate reserve figures.

Certain complications arise in assessing representative capital costs. Capital spending, for example, generally occurs over a number of years, particularly in the case of natural gas, making the time frame of the analysis an important parameter. In Western Canada, the period from land purchase to final development can range from one year, to in excess of 10 years for a field such as Caroline. In addition, various incentives have been available to the industry from governments that reduce the net costs of exploring for, and developing oil and gas reserves. These incentives are significant for some companies but not to others. Other issues, such as capitalization of interest and overheads further complicate the task of calculating capital applicable to reserve exploitation.

Other complications exist in determining the reserves associated with exploration and development activity. Reserve classification, proved versus probable, is a major factor in F&D calculations. Many companies consider both proved and probable reserves in their internal F&D calculations, while others use only proved. Another aspect is which point in the F&D cycle reserves are recognized. Generally, reserves may be known to exist, but will not be recognized until "commerciality" is achieved (based on production, price and economic return), even if substantial capital has been spent. This is the case for frontier, international and numerous heavy oil projects. In addition, F&D costs do not reflect the quality, and hence the value of the reserves added.

These are some of the complications and shortcomings of F&D cost analysis. Nevertheless, companies with calculated low F&D costs have achieved good success in exploration and development that has generally then been reflected in growth in reserves, production, and good share price performance. Conversely, those companies with high F&D costs have generally had poor success (and in many cases been unable to replace reserves), and poor market performance.

We have calculated F&D costs over the five year time period from 1986 to 1990 inclusive. The analysis commences in 1986, post the price collapse and full implementation of the Western Accord which initiated a new era in Canadian exploration activity. This new era is characterized by significant reductions in professional staff levels, elimination of PIP grants, phasing out of other exploration incentives, substantially lower commodity prices (revenues) and lower capital costs. This trend has continued into 1991 with poor gas prices and high light/heavy crude differentials.

The published results reflect a five year weighted average. The weighted average captures the time sensitive nature of oil and gas exploration such as delays in bringing new reserves onstream, delineation of discoveries, and the impact of a focused exploration strategy. The weighted average mitigates short-term influences and focuses instead on the medium-term impact of a company's exploration program.

Our methodology for calculating F&D costs is presented as follows:

Proved Reserves

Proved reserves (additions plus revisions) were considered exclusively. This was to maintain a consistent basis of comparison since certain companies do not report probable reserves. Also, probable reserves by their nature are less certain, and even when risked, can misrepresent the true exploration success of a company. Generally, the realization of probable reserves is outside the direct control of a company as they are based on technical factors associated with reservoir performance. In a number of instances, probable reserves are captured in revisions as they become proved.

Reserve Additions plus Revisions

Both proved reserve additions and proved reserve additions plus revisions are analyzed. Reserve additions provide a measure of exploration success on a year by year basis. However, this measure may be unrepresentative of the quality of a company's exploration success if there is appreciation (ex. ***Shell Canada, Imperial Oil, Renaissance***) or depreciation (ex. ***Poco Petroleums, Numac Oil & Gas***) of reserves over time. Using a weighted average over a period of years and including reserve revisions will capture this appreciation (or depreciation) in the reserve base as well as the differences in the approaches to booking reserves among the companies analyzed. Nevertheless, revisions for reserves may be added (or deleted) outside the reference period skewing the results. Where significant and identifiable, we have adjusted for these particular revisions in the analysis.

Capital Expenditures

We have excluded corporate expenditures, capitalized G&A (general and administrative) and interest expenses, and exploration incentive payments from the capital expenditures used in the analysis. We exclude capitalized items as some oil and gas companies do not capitalize G&A and interest and they are of an expense rather than capital nature. Incentive payments are not considered as they do not apply equally to all companies and distort F&D costs performance.

We have included capital expenditures (and reserves) for international and frontier but note that with the exception of ***Coho Resources, Ranger Oil***, and ***Bow Valley Industries***, most of these companies were primarily focused in Canada over this period.

Acquisitions

Acquisitions and divestitures are not included in the capital or reserve figures as these activities are not part of the exploration process. Incremental reserves resulting from exploitation of acquired properties are recognized in future years.

Heavy and Synthetic Oil

Heavy and synthetic oil reserves and capital have been excluded as they are more in the nature of mining projects than conventional oil and gas exploration and development.

Finding and Development Costs

The accompanying table presents the five year average F&D costs and reserve replacement ratios for 23 of the largest publicly traded oil and gas companies in Canada.

Table APPV.1

FIVE YEAR FINDING AND DEVELOPMENT COST STUDY
1986 - 1990

	F&D Additions + Revisions		F&D Additions		Replacement Ratio
Coho Resources	4.19	Coho Resources	2.82	Coho Resources	4.02
Shell Canada	4.75	Morrison Petroleums	4.78	Renaissance Energy	3.07
Saskoil	4.76	Renaissance Energy	5.25	Morrison Petroleums	2.50
Renaissance Energy	4.82	Shell Canada	6.40	Anderson Exploration	2.11
Morrison Petroleums	5.28	North Canadian	6.59	Saskoil	1.71
Sceptre Resources	5.28	Poco Petroleums	7.93	Shell Canada	1.64
Anderson	5.39	Bow Valley	8.06	Chauvco Resources	1.62
Norcen Energy	5.44	Sceptre Resources	8.77	North Canadian	1.56
Chauvco Resources	6.73	Saskoil	9.00	Norcen Energy	1.51
North Canadian	6.88	Encor	10.23	Bow Valley	1.15
Gulf Canada	7.58	Chauvco Resources	10.31	Mark Resources	1.12
Encor	7.73	Anderson	10.60	Poco Petroleums	1.08
Imperial Oil	7.87	Norcen Energy	11.59	Sceptre Resources	1.08
Bow Valley	8.51	Alberta Energy	11.82	Gulf Canada	0.86
Mark Resources	8.67	Numac Oil & Gas	12.05	Alberta Energy	0.85
Ranger Oil	8.92	Ranger Oil	12.17	Numac Oil & Gas	0.81
PanCanadian	9.71	PanCanadian	12.62	Ranger Oil	0.72
Canadian OXY	10.72	Gulf Canada	14.44	Canadian OXY	0.66
Alberta Energy	11.15	BP Canada	14.73	Imperial Oil	0.64
BP Canada	11.55	Mark Resources	15.88	BP Canada	0.64
Petro-Canada	12.59	Imperial Oil	16.45	Petro-Canada	0.63
Poco Petroleums	12.77	Canadian OXY	23.92	Encor	0.63
Numac Oil & Gas	18.66	Petro-Canada	27.39	PanCanadian	0.59

Notes:
1. Proved reserves only.
2. F&D costs exclude reserve acquisitions and dispositions.
3. F&D is calculated for reserve additions plus revisions and for additions only
4. F&D costs listed are the 5 year weighted average, 1986 to 1990.
5. Gas equivalent is calculated at 12:1 conversion.
6. Costs are net of capitalized expenses, government incentive payments are not considered.
7. Costs are for conventional activity only, but include international and frontier expenditures.

One of our key conclusions in assessing exploration and development results is that F&D costs are relatively high for the industry, and are steadily increasing. This trend is apparent when observing the five year moving average trends in F&D costs for the industry over the past three years of $6.27, $6.72 and $7.74/BOE, as described earlier in this report. Though these costs are below the historical highs of the early 1980's, those early costs were generated in a period of much higher price expectations for the industry. Prior to 1986, companies were willing to invest more in land, seismic and exploration as a higher real price environment was universally forecast. Current F&D costs are substantially higher than F&D costs prior to 1980 when the basin was less developed and most of the industry's major oil and gas reservoirs were being discovered.

For the 23 companies shown in the tables, the weighted five year (1986-1990) average F&D costs were $7.38/BOE, which is roughly comparable to industry averages. We view the increasing F&D costs as an indication of the maturity of the Western Canadian sedimentary basin, which will impact the future growth and profitability prospects of the industry in Canada.

Table APPV.2

FINDING AND DEVELOPMENT COSTS - FIVE YEAR TREND
Additions Plus Revisions ($/BOE)

	1986	1987	1988	1989	1990	Average	Replacement Ratio
Coho Resources	1.15	0.73	2.77	13.23	(14.61)	4.03	4.52
Shell Canada	5.98	2.45	4.03	5.68	8.24	4.75	1.64
Saskoil	5.10	3.75	5.60	6.64	3.98	4.76	1.71
Renaissance Energy	5.05	3.67	5.65	4.68	5.14	4.82	3.07
Morrison Petroleums	4.83	4.06	4.18	5.85	7.66	5.28	2.50
Sceptre Resources	2.91	4.36	7.31	4.65	6.09	5.28	1.08
Anderson Exploration	2.78	1.17	7.50	8.68	21.58	5.39	2.11
Norcen Energy	9.99	2.13	6.26	7.43	6.59	5.44	1.51
Chauvco Resources	2.88	3.49	34.97	5.02	10.40	6.73	1.62
North Canadian Oils	9.51	3.24	7.76	10.12	9.32	6.88	1.56
Imperial Oil	6.53	11.07	13.11	3.13	(18.09)	7.87	0.64
Encor Inc.	0.00	0.00	10.09	6.65	6.33	7.73	0.63
Gulf Canada	5.79	7.72	10.87	7.32	7.10	7.63	.86
Bow Valley Industries	27.57	8.45	10.16	9.79	3.80	8.51	1.15
Ranger Oil	49.35	17.15	50+	12.00	4.91	8.92	0.72
Mark Resources	0.00	11.54	8.14	45.94	5.15	8.67	1.12
PanCanadian	24.47	9.42	12.54	12.25	5.92	9.71	0.59
Canadian Occidental	6.89	9.96	10.07	13.43	16.24	10.72	0.66
BP Canada	3.59	(12.0)	14.11	11.44	13.91	11.55	0.64
Poco Petroleums	7.74	8.23	(37.20)	50+	6.71	12.77	1.08
Alberta Energy	21.20	4.95	24.63	11.87	8.96	11.15	0.85
Petro-Canada	23.90	8.77	6.54	11.55	(50+)	12.59	0.63
Numac Oil & Gas	(37.22)	11.29	22.97	(28.71)	5.82	18.66	0.81
Average	9.06	5.31	8.23	6.54	8.86	7.38	0.89

Note: Annual totals are weighted average F&D costs.

The accompanying table presenting the yearly F&D cost trend from 1986 to 1990 and the 5 year average illustrates the importance of interpreting F&D costs over a period of time rather than drawing conclusions on annual results alone. F&D costs for one year can skew the evaluation of E&D performance as exploration concepts take years to develop, and there can often be pronounced lags in reserve booking and capital expenditures.

Replacement ratio (RR) compares the volume of proved reserve additions plus revisions to the volume of production. The overall RR for the past five years of the 23 companies is a disappointing 89%, indicating that these companies were unable to replace production. This ratio has been heavily influenced by the performance of senior companies who were unable to replace reserves produced over the past five years; in particular ***Petro-Canada, PanCanadian, BP Canada, Imperial, CanadianOXY*** and ***Gulf***. Not surprisingly the companies with the best RR's were generally those with the best F&D records and those that were unable to replace production were the companies with the less successful programs and higher F&D costs.

APPENDIX VI

INDUSTRY OUTLOOK – DETAILED TABLES

List of tables in Appendix VI

Canadian Oil and Gas Upstream Industry Outlook: Chenery Dobson Low Prices

Chenery Dobson Low Prices -- Balance Sheet, Sources and Uses of Funds, Interest Expense

Canadian Oil and Gas Upstream Industry Outlook: Chenery Dobson High Prices

Chenery Dobson High Prices -- Balance Sheet, Sources and Uses of Funds, Interest Expense

Canadian Oil and Gas Upstream Industry Outlook
Chenery Dobson Low Prices

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Production/Sales												
L & M Oil (MB/d)	928	890	832	772	713	658	608	591	642	613	590	571
Conv'l Heavy (MB/d)	291	310	310	303	292	280	269	262	259	258	259	262
Bitumen (MB/d)	129	135	135	145	155	155	155	155	155	155	155	155
Synthetic (MB/d)	205	208	225	225	230	230	230	230	230	230	230	230
C5+ (MB/d)	120	116	120	125	155	155	151	147	143	139	135	132
Natural Gas (Bcf)	3402	3396	3500	3667	3880	4107	4191	4234	4262	4290	4319	4349
L.P.G.'s (MB/d)	287	314	320	330	386	388	390	392	394	396	398	400
Sulphur Sales(1000 mt)	6219	6200	6500	6500	6500	6500	6500	6500	6500	6500	6500	6500
Total Prod'n (MBOE/d)	2736	2748	2740	2737	2817	2804	2760	2744	2795	2771	2754	2742
Prices												
WTI Prices	19.60	24.48	21.00	19.80	21.29	22.89	24.63	26.47	27.78	29.16	30.61	32.22
FOB Edmonton Light	22.16	27.65	23.75	22.75	23.25	24.50	26.25	29.00	33.00	36.50	40.00	42.50
Average Wellhead ($/B)	19.60	23.83	19.59	18.60	18.93	20.01	21.58	24.19	28.21	31.49	34.82	37.11
L & M Oil ($/B)	20.94	25.65	21.76	20.70	21.17	22.39	24.11	26.83	30.79	34.26	37.75	40.22
Light/Heavy Diff ($/B)	5.63	7.03	8.00	7.44	7.70	7.98	8.25	8.59	9.00	9.35	9.62	9.90
Conv'l Heavy ($/B)	15.31	18.62	13.76	13.26	13.47	14.41	15.86	18.24	21.79	24.91	28.13	30.32
Light/Bitumen Diff ($/B)	9.29	10.04	11.00	10.62	11.00	11.39	11.79	12.27	12.85	13.35	13.74	14.14
Bitumen ($/B)	11.65	15.61	10.76	10.08	10.17	11.00	12.32	14.56	17.94	20.91	24.01	26.08
Synthetic ($/B)	21.12	25.76	21.87	20.80	21.26	22.48	24.21	26.94	30.90	34.38	37.87	40.35
C5+ ($/B)	21.31	26.63	22.09	21.00	21.46	22.68	24.42	27.16	31.13	34.63	38.13	40.63
Natural Gas ($/Mcf)	1.52	1.55	1.35	1.25	1.30	1.40	1.60	1.80	2.05	2.35	2.70	3.00
L.P.G.'s ($/B)	7.08	8.46	8.31	7.96	8.14	8.58	9.19	10.15	11.55	12.77	14.00	14.87
Sulphur ($/mt)	65.59	72.32	69.66	72.16	76.27	80.18	84.13	88.51	92.92	97.65	102.64	107.77
Average Price per BOE	17.73	20.82	17.44	16.35	16.55	17.52	19.18	21.45	24.74	27.79	31.08	33.60
Production Revenue												
L & M Oil (MB/d)	7093	8332	6605	5834	5509	5377	5351	5787	7211	7670	8136	8383
Conv'l Heavy	1626	2107	1555	1467	1436	1475	1560	1744	2056	2343	2661	2895
Bitumen	549	769	530	533	575	622	697	824	1015	1183	1358	1475
Synthetic	1580	1956	1796	1708	1785	1887	2032	2261	2594	2886	3179	3388
C5+	933	1128	968	958	1213	1283	1344	1454	1622	1756	1882	1950
Natural Gas	5183	5264	4725	4583	5044	5750	6706	7621	8737	10082	11661	13047
L.P.G.'s	741	1332	1268	1249	1456	1533	1631	1788	2006	2182	2365	2493
Sulphur	408	448	453	469	496	521	547	575	604	635	667	701
Total Production Revenue	18113	21336	17899	16802	17514	18449	19867	22055	25846	28736	31910	34332
Operating Costs and G & A												
Conventional	5240	5414	5625	5874	6336	6618	6821	7114	7633	7933	8271	8641
Avg. Unit Costs $/BOE	5.98	6.17	6.47	6.80	7.14	7.49	7.87	8.26	8.68	9.11	9.57	10.04
Non-Conventional	1515	1539	1696	1831	2000	2100	2205	2334	2514	2639	2770	2907
Avg. Unit Costs $/BOE	12.43	12.30	12.91	13.56	14.23	14.95	15.69	16.48	17.30	18.17	19.08	20.03
Total Operating Costs	6756	6953	7321	7705	8336	8718	9027	9448	10148	10571	11041	11548
Avg. Unit Costs $/BOE	6.76	6.93	7.32	7.71	8.11	8.52	8.96	9.43	9.95	10.45	10.98	11.54
Interest Payments	1500	1407	1348	1477	1596	1687	1744	1757	1749	1728	1720	1721
Cash From Operations After Debt Service	9857	12976	9229	7620	7582	8044	9096	10850	13949	16436	19149	21062
Royalties and Taxes												
Royalties Paid	2971	3619	2901	2634	2775	2938	3228	3654	4378	4992	5681	6206
Average per BOE	2.97	3.61	2.90	2.64	2.70	2.87	3.20	3.65	4.29	4.94	5.65	6.20
Effective Royalty Rate	16.4%	17.0%	16.2%	15.7%	15.8%	15.9%	16.2%	16.6%	16.9%	17.4%	17.8%	18.1%
ARTC	387	166	219	236	215	190	163	135	115	93	80	80
Total Net Royalties	2584	3453	2682	2398	2560	2748	3065	3519	4264	4898	5600	6126
P.G.R.T./Other Taxes	0	0	0	0	0	0	0	0	0	0	0	0
Fed. Income Tax	408	903	391	0	0	115	360	697	1272	1642	2042	2228
Prov. Income Tax	347	394	46	0	0	0	0	168	463	640	830	900
Current Income Taxes	755	1297	437	0	0	115	360	865	1735	2282	2872	3128
Average per BOE	0.76	1.29	0.44	0.00	0.00	0.11	0.36	0.86	1.70	2.26	2.86	3.12
Effective Taxation Rate	4.2%	6.1%	2.4%	0.0%	0.0%	0.6%	1.8%	3.9%	6.7%	7.9%	9.0%	9.1%
After Tax Cash Flow	6518	8226	6110	5222	5022	5181	5671	6466	7950	9256	10676	11809
Average Per BOE	6.53	8.20	6.11	5.23	4.88	5.06	5.63	6.46	7.79	9.15	10.62	11.80

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Non–Cash Charges												
Depreciation	1254	1107	1233	1394	1548	1682	1759	1860	2003	2126	2289	2468
Depletion	2462	2567	2581	2683	2852	2969	3007	3082	3228	3337	3495	3678
Total	3716	3674	3814	4077	4401	4650	4766	4942	5231	5463	5784	6146
Average Per BOE	3.72	3.66	3.81	4.08	4.28	4.54	4.73	4.93	5.13	5.40	5.75	6.14
Deferred Taxes	443	519	322	176	62	-31	6	-47	-110	-19	54	196
Exploration Expenses	1097	1155	1155	999	895	872	898	1024	1259	1466	1691	1871
Writeoffs	653	1004	550	550	550	550	550	550	550	550	550	550
Other	219	81	50	50	50	50	50	50	50	50	50	50
Earnings from Operations	390	1793	220	-630	-936	-911	-598	-53	969	1746	2548	2996
Profitability												
Capital Employed	59076	60079	61706	62704	62398	62130	61153	60510	60029	60155	61171	62552
Return on Capital Employed	2.8%	5.2%	2.1%	0.6%	0.0%	0.0%	0.6%	1.5%	3.1%	4.5%	5.9%	6.7%
Equity	29082	30256	30238	29058	27572	26111	24963	24360	24392	24889	25868	27116
Return on Capital Employed	1.3%	6.0%	0.7%	-2.1%	-3.3%	-3.4%	-2.3%	-0.2%	4.0%	7.1%	10.0%	11.3%
Investment												
Conventional												
Land Bonuses	738	840	800	700	633	617	635	724	890	1037	1196	1323
G&G	544	627	600	550	475	462	476	543	668	778	897	992
Explor. Drilling	1061	1215	1200	980	972	947	975	1112	1367	1592	1836	2031
Total Exploratory	2343	2683	2600	2230	2079	2026	2087	2379	2925	3406	3929	4346
Dev. Drilling	942	1118	1250	1100	904	881	907	1035	1272	1481	1708	1889
Dev. Facilities	1680	1705	2180	1950	1311	1277	1316	1500	1844	2147	2477	2740
Gas Plants	427	471	325	275	226	220	227	259	318	370	427	472
Total Development	3049	3294	3755	3325	2440	2378	2450	2793	3434	3999	4612	5102
Total Conventional	5392	5977	6355	5555	4519	4404	4537	5173	6360	7405	8541	9447
Average Per BOE	6.15	6.81	7.31	6.43	5.09	4.99	5.23	6.01	7.23	8.50	9.88	10.98
Non–Conventional												
Alberta Oil Sands	304	731	200	220	200	200	200	200	200	200	200	200
Northern Canada	310	128	50	NA	NA	NA	NA	NA	NA	NA	NA	NA
Eastern Offshore	138	201	540	850	820	1200	500	500	0	0	300	300
Other	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Non–Conventional	753	1059	790	1070	1020	1400	700	700	200	200	500	500
Total Investment	6145	7036	7145	6625	5539	5804	5237	5873	6560	7605	9041	9947
Incentives	198	0	0	0	0	0	0	0	0	0	0	0
Total Net Investment	5947	7036	7145	6625	5539	5804	5237	5873	6560	7605	9041	9947
Average Per BOE	5.95	7.01	7.14	6.63	5.39	5.67	5.20	5.86	6.43	7.52	8.99	9.94
Reinv't Ratio--Conv'l Areas	83%	73%	104%	106%	90%	85%	80%	80%	80%	80%	80%	80%
Reinvestment Ratio - Total	94%	86%	117%	127%	110%	112%	92%	91%	83%	82%	85%	84%
Drilling Activity												
Total Wells	5651	5886	5724	4894	4203	3900	3827	4155	4866	5396	5927	6244
Expl'n	2525	2696	2609	2130	2012	1867	1832	1989	2329	2583	2837	2989
Dev't	3126	3190	3086	2750	2152	1997	1960	2128	2491	2763	3035	3197
Oil	1781	2042	2160	1678	1274	1150	1120	1320	1577	1760	1935	2023
Gas	2313	2226	2070	1939	1832	1732	1708	1751	2019	2227	2445	2592
Rig Count	159	170	175	151	124	116	114	130	150	163	176	186
Rig Utilization	31%	36%	38%	33%	27%	25%	25%	28%	33%	35%	38%	40%
Drilling Costs ($M/Well)												
Total	354	396	428	425	446	469	492	517	542	570	598	628
Exploration	420	451	460	460	483	507	533	559	587	616	647	680
Development	301	350	405	400	420	441	463	486	511	536	563	591
Reserves Trends												
Oil Reserves (MMB)	4545	4242	4026	3790	3541	3306	3090	2892	2670	2476	2305	2149
Oil Additions (MMB)	233	115	201	156	118	107	104	123	147	164	180	188
Oil Finding Rate (MB/W)	82	93	93	93	93	93	93	93	93	93	93	93
Gas Reserves	71.2	70.9	70.1	68.9	67.4	65.6	63.6	61.7	60.0	58.6	57.5	56.5
Gas Additions	5.1	3.5	2.7	2.5	2.4	2.3	2.2	2.3	2.6	2.9	3.2	3.4
Gas Finding Rate (Bcf/Well) (3-Yr MAVG)	1.0	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
F & D Costs												
Oil ($/B)	11.35	11.73	15.33	15.70	14.86	15.61	16.39	17.21	18.07	18.97	19.92	20.91
Gas ($/Mcf)	0.41	0.52	0.70	0.71	0.67	0.70	0.73	0.77	0.81	0.85	0.90	0.94
BOE ($/BOE 12:1)	7.74	8.52	10.76	10.66	9.75	10.17	10.65	11.43	12.07	12.70	13.34	13.97

Source: PowerWest

Chenery Dobson Low Prices

Balance Sheet

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Current Assets	8000	9388	7876	7393	7706	8117	8741	9704	11372	12644	14040	15106
Net PP&E	57876	59079	60706	61704	61398	61130	60153	59510	59029	59155	60171	61552
Total Assets	65876	68467	68581	69097	69104	69247	68894	69214	70401	71799	74211	76658
Current Liabilities	6800	8388	6876	6393	6706	7117	7741	8704	10372	11644	13040	14106
Deferred Taxes	9305	9824	10146	10322	10384	10353	10359	10312	10202	10183	10237	10433
Equity	29082	30256	30238	29058	27572	26111	24963	24360	24392	24889	25868	27116
Debt	19000	18513	20014	22174	23430	24774	25047	25148	24828	24548	24596	24589
Take or Pay	1689	1486	1308	1151	1013	891	784	690	607	534	470	414
Total Liabilities	65876	68467	68581	69097	69104	69247	68894	69214	70401	71799	74211	76658

Sources and Uses of Funds

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Cash Flow	6518	8226	6110	5222	5022	5181	5671	6466	7950	9256	10676	11809
New Debt	2000	-237	1501	2160	1256	1344	273	101	-319	-280	48	-7
New Equity	2000	700	700	300	300	300	300	300	300	300	300	300
Other	0	-203	-178	-157	-138	-122	-107	-94	-83	-73	-64	-56
Total Sources	10518	8486	8133	7525	6439	6704	6137	6773	7847	9203	10960	12046
Capital Exp.	5947	7036	7145	6625	5539	5804	5237	5873	6560	7605	9041	9947
Working Capital Change	200	-200	0	0	0	0	0	0	0	0	0	0
Dividends	1100	1400	988	900	900	900	900	900	1288	1598	1919	2099
Debt Retirement	0	250	0	0	0	0	0	0	0	0	0	0
Total Application	7247	8486	8133	7525	6439	6704	6137	6773	7847	9203	10960	12046

Interest Expense

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Open	21000	19000	18513	20014	22174	23430	24774	25047	25148	24828	24548	24596
New	2000	-237	1501	2160	1256	1344	273	101	-319	-280	48	-7
Retired	0	250	0	0	0	0	0	0	0	0	0	0
Year-end	19000	18513	20014	22174	23430	24774	25047	25148	24828	24548	24596	24589
Rate	7.5%	7.5%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
Interest Expense	1500	1407	1348	1477	1596	1687	1744	1757	1749	1728	1720	1721

Source: PowerWest

Canadian Oil and Gas Upstream Industry Outlook
Chenery Dobson High Prices

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Production/Sales												
L & M Oil (MB/d)	928	890	832	778	727	679	640	636	702	686	673	659
Conv'l Heavy (MB/d)	291	310	310	308	304	300	298	304	313	324	335	344
Bitumen (MB/d)	129	135	135	145	155	155	155	155	155	155	155	155
Synthetic (MB/d)	205	208	225	225	230	230	230	230	230	230	230	230
C5+ (MB/d)	120	116	120	125	155	155	151	147	143	139	135	132
Natural Gas (Bcf)	3402	3396	3500	3667	3880	4107	4191	4234	4262	4290	4319	4349
L.P.G.'s (MB/d)	287	314	320	330	386	388	390	392	394	396	398	400
Sulphur Sales(1000 mt)	6219	6200	6500	6500	6500	6500	6500	6500	6500	6500	6500	6500
Total Prod'n (MBOE/d)	2736	2748	2740	2748	2843	2845	2820	2831	2910	2909	2913	2912
Prices												
WTI Prices	19.60	24.48	21.00	22.00	23.00	24.55	28.39	33.15	36.49	38.91	41.31	41.38
FOB Edmonton Light	22.16	27.65	23.75	25.00	27.00	28.70	33.20	38.30	42.70	45.50	48.30	48.30
Average Wellhead ($/B)	19.60	23.83	19.59	20.84	22.65	24.15	28.44	33.36	37.71	40.26	42.85	42.63
L & M Oil ($/B)	20.94	25.65	21.76	22.95	24.92	26.59	31.06	36.13	40.49	43.26	46.05	46.02
Light/Heavy Diff ($/B)	5.63	7.03	8.00	7.44	7.70	7.98	8.25	8.59	9.00	9.35	9.62	9.90
Conv'l Heavy ($/B)	15.31	18.62	13.76	15.51	17.22	18.61	22.81	27.54	31.49	33.91	36.43	36.12
Light/Bitumen Diff ($/B)	9.29	10.04	11.00	10.62	11.00	11.39	11.79	12.27	12.85	13.35	13.74	14.14
Bitumen ($/B)	11.65	15.61	10.76	12.33	13.92	15.20	19.27	23.86	27.64	29.91	32.31	31.88
Synthetic ($/B)	21.12	25.76	21.87	23.06	25.03	26.70	31.18	36.27	40.63	43.41	46.20	46.17
C5+ ($/B)	21.31	26.63	22.09	23.28	25.26	26.94	31.46	36.57	40.94	43.72	46.52	46.49
Natural Gas ($/Mcf)	1.52	1.55	1.35	1.45	1.80	2.20	2.70	3.20	3.70	4.20	4.50	4.50
L.P.G.'s ($/B)	7.08	8.46	8.31	8.75	9.45	10.05	11.62	13.40	14.95	15.92	16.90	16.90
Sulphur ($/mt)	65.59	72.32	69.66	72.16	76.27	80.18	84.13	88.51	92.92	97.65	102.64	107.77
Average Price per BOE	17.73	20.82	17.44	18.50	20.70	23.15	27.68	32.53	37.03	40.53	43.26	43.14
Production Revenue												
L & M Oil (MB/d)	7093	8332	6605	6514	6609	6593	7250	8394	10369	10827	11312	11075
Conv'l Heavy	1626	2107	1555	1744	1913	2037	2482	3052	3603	4013	4460	4529
Bitumen	549	769	530	653	788	860	1090	1350	1564	1692	1828	1804
Synthetic	1580	1956	1796	1894	2101	2241	2618	3045	3411	3644	3878	3876
C5+	933	1128	968	1062	1428	1524	1732	1959	2133	2217	2295	2232
Natural Gas	5183	5264	4725	5317	6984	9035	11316	13549	15769	18018	19436	19571
L.P.G.'s	741	1332	1268	1372	1658	1744	2002	2269	2488	2625	2777	2771
Sulphur	408	448	453	469	496	521	547	575	604	635	667	701
Total Production Revenue	18113	21336	17899	19024	21976	24556	29037	34193	39942	43671	46653	46557
Operating Costs and G & A												
Conventional	5240	5414	5625	5900	6403	6729	6994	7377	7997	8394	8825	9265
Avg. Unit Costs $/BOE	5.98	6.17	6.47	6.80	7.14	7.49	7.87	8.26	8.68	9.11	9.57	10.04
Non-Conventional	1515	1539	1696	1831	2000	2100	2205	2334	2514	2639	2770	2907
Avg. Unit Costs $/BOE	12.43	12.30	12.91	13.56	14.23	14.95	15.69	16.48	17.30	18.17	19.08	20.03
Total Operating Costs	6756	6953	7321	7731	8404	8830	9199	9711	10512	11033	11595	12172
Avg. Unit Costs $/BOE	6.76	6.93	7.32	7.71	8.10	8.50	8.94	9.40	9.90	10.39	10.91	11.45
Interest Payments	1500	1407	1348	1462	1568	1661	1723	1756	1779	1787	1801	1814
Cash From Operations After Debt Service	9857	12976	9229	9831	12004	14065	18114	22726	27651	30851	33257	32570
Royalties and Taxes												
Royalties Paid	2971	3619	2901	3106	3776	4376	5381	6518	7754	8624	9253	9167
Average per BOE	2.97	3.61	2.90	3.10	3.64	4.21	5.23	6.31	7.30	8.12	8.70	8.62
Effective Royalty Rate	16.4%	17.0%	16.2%	16.3%	17.2%	17.8%	18.5%	19.1%	19.4%	19.7%	19.8%	19.7%
ARTC	387	166	219	204	188	164	105	80	80	80	80	80
Total Net Royalties	2584	3453	2682	2902	3587	4212	5276	6438	7673	8544	9173	9087
P.G.R.T./Other Taxes	0	0	0	0	0	0	0	0	0	0	0	0
Fed. Income Tax	408	903	391	419	748	1091	1813	2539	3278	3583	3761	3317
Prov. Income Tax	347	394	46	47	191	355	716	1069	1425	1540	1605	1342
Current Income Taxes	755	1297	437	466	940	1446	2528	3608	4703	5123	5366	4659
Average per BOE	0.76	1.29	0.44	0.47	0.91	1.39	2.46	3.49	4.43	4.82	5.05	4.38
Effective Taxation Rate	4.2%	6.1%	2.4%	2.5%	4.3%	5.9%	8.7%	10.6%	11.8%	11.7%	11.5%	[illegible]
After Tax Cash Flow	6518	8226	6110	6462	7477	8407	10310	12681	15275	17185	18718	[illegible]
Average Per BOE	6.53	8.20	6.11	6.44	7.21	8.10	10.02	12.27	14.38	16.18	17.61	17.71

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Non-Cash Charges												
Depreciation	1254	1107	1233	1396	1585	1757	1883	2051	2267	2450	2654	2848
Depletion	2462	2567	2581	2699	2907	3063	3157	3313	3550	3734	3949	4157
Total	3716	3674	3814	4095	4492	4820	5041	5364	5817	6184	6603	7005
Average Per BOE	3.72	3.66	3.81	4.08	4.33	4.64	4.90	5.19	5.48	5.82	6.21	6.59
Deferred Taxes	443	519	322	351	339	323	385	528	687	1028	1295	1593
Exploration Expenses	1097	1155	1155	1181	1332	1415	1633	2009	2420	2722	2965	2982
Writeoffs	653	1004	550	550	550	550	550	550	550	550	550	550
Other	219	81	50	50	50	50	50	50	50	50	50	50
Earnings from Operations	390	1793	220	235	714	1249	2651	4180	5752	6651	7255	6645
Profitability												
Capital Employed	59076	60079	61706	63235	64610	66371	68095	71017	74651	79142	84498	89521
Return on Capital Employed	2.8%	5.2%	2.1%	2.3%	3.0%	3.8%	6.0%	8.2%	10.2%	11.3%	11.7%	10.6%
Equity	29082	30256	30238	29829	29708	29907	30948	32905	35807	39247	43050	46487
Return on Equity	1.3%	6.0%	0.7%	0.8%	2.4%	4.2%	8.7%	13.1%	16.7%	17.7%	17.6%	14.8%
Investment												
Conventional												
Land Bonuses	738	840	800	810	942	1000	1155	1420	1711	1925	2096	2108
G&G	544	627	600	600	707	750	866	1065	1283	1444	1572	1581
Explor. Drilling	1061	1215	1200	1275	1447	1536	1773	2181	2627	2956	3219	3238
Total Exploratory	2343	2683	2600	2685	3096	3287	3794	4666	5621	6324	6888	6927
Dev. Drilling	942	1118	1250	1250	1346	1429	1650	2029	2444	2750	2995	3012
Dev. Facilities	1680	1705	2180	2050	1952	2072	2392	2942	3544	3987	4342	4367
Gas Plants	427	471	325	300	336	357	412	507	611	687	749	753
Total Development	3049	3294	3755	3600	3634	3859	4454	5478	6599	7424	8086	8132
Total Conventional	5392	5977	6355	6285	6729	7146	8248	10144	12220	13748	14974	15060
Average Per BOE	6.15	6.81	7.31	7.24	7.50	7.96	9.28	11.36	13.26	14.92	16.23	16.33
Non-Conventional												
Alberta Oil Sands	304	731	200	220	200	200	200	200	200	200	200	200
Northern Canada	310	128	50	NA	NA	NA	NA	NA	NA	NA	NA	NA
Eastern Offshore	138	201	540	850	820	1200	500	500	0	0	300	300
Other	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Non-Conventional	753	1059	790	1070	1020	1400	700	700	200	200	500	500
Total Investment	6145	7036	7145	7355	7749	8546	8948	10844	12420	13948	15474	15560
Incentives	198	0	0	0	0	0	0	0	0	0	0	0
Total Net Investment	5947	7036	7145	7355	7749	8546	8948	10844	12420	13948	15474	15560
Average Per BOE	5.95	7.01	7.14	7.33	7.47	8.23	8.69	10.49	11.69	13.13	14.56	14.64
Reinv't Ratio--Conv'l Areas	83%	73%	104%	97%	90%	85%	80%	80%	80%	80%	80%	80%
Reinvestment Ratio - Total	94%	86%	117%	114%	104%	102%	87%	86%	81%	81%	83%	83%
Drilling Activity												
Total Wells	5651	5886	5724	5941	6258	6329	6957	8149	9350	10017	10391	9953
Expl'n	2525	2696	2609	2772	2996	3029	3330	3901	4475	4795	4974	4764
Dev't	3126	3190	3086	3125	3204	3241	3562	4173	4787	5129	5321	5096
Oil	1781	2042	2160	2061	1890	1796	1984	2539	2917	3055	3169	3009
Gas	2313	2226	2070	2330	2735	2881	3157	3483	3993	4348	4510	4346
Rig Count	159	170	175	183	185	189	208	255	288	301	308	295
Rig Utilization	31%	36%	38%	40%	40%	41%	45%	55%	63%	66%	67%	64%
Drilling Costs ($M/Well)												
Total	354	396	428	425	446	469	492	517	542	570	598	628
Exploration	420	451	460	460	483	507	533	559	587	616	647	680
Development	301	350	405	400	420	441	463	486	511	536	563	591
Reserves Trends												
Oil Reserves (MMB)	4545	4242	4026	3822	3621	3431	3273	3157	3018	2893	2780	2653
Oil Additions (MMB)	233	115	201	192	176	167	185	236	271	284	295	280
Oil Finding Rate (MB/W)	82	93	93	93	93	93	93	93	93	93	93	93
Gas Reserves	71.2	70.9	70.1	69.5	69.1	68.8	68.7	69.0	69.9	71.3	72.8	74.1
Gas Additions	5.1	3.5	2.7	3.0	3.6	3.7	4.1	4.5	5.2	5.7	5.9	5.6
Gas Finding Rate (Bcf/Well) (3-Yr MAVG)	1.0	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
F & D Costs												
Oil ($/B)	11.35	11.73	15.33	14.66	14.86	15.61	16.39	17.21	18.07	18.97	19.92	20.91
Gas ($/Mcf)	0.41	0.52	0.70	0.66	0.67	0.70	0.73	0.77	0.81	0.85	0.89	0.94
BOE ($/BOE 12:1)	7.74	8.52	10.76	9.97	9.74	10.07	10.59	11.37	11.94	12.46	13.09	13.71

Source: PowerWest

Chenery Dobson High Prices

Balance Sheet

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Current Assets	8000	9388	7876	8370	9669	10804	12776	15045	17574	19215	20527	20485
Net PP&E	57876	59079	60706	62235	63610	65371	67095	70017	73651	78142	83498	88521
Total Assets	65876	68467	68581	70605	73279	76176	79871	85062	91225	97358	104025	109006
Current Liabilities	6800	8388	6876	7370	8669	9804	11776	14045	16574	18215	19527	19485
Deferred Taxes	9305	9824	10146	10497	10836	11159	11544	12073	12760	13787	15082	16675
Equity	29082	30256	30238	29829	29708	29907	30948	32905	35807	39247	43050	46487
Debt	19000	18513	20014	21758	23054	24414	24819	25349	25477	25573	25896	25945
Take or Pay	1689	1486	1308	1151	1013	891	784	690	607	534	470	414
Total Liabilities	65876	68467	68581	70605	73279	76176	79871	85062	91225	97358	104025	109006

Sources and Uses of Funds

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Cash Flow	6518	8226	6110	6462	7477	8407	10310	12681	15275	17185	18718	18824
New Debt	2000	-237	1501	1744	1296	1360	405	530	128	96	322	49
New Equity	2000	700	700	300	300	300	300	300	300	300	300	300
Other	0	-203	-178	-157	-138	-122	-107	-94	-83	-73	-64	-56
Total Sources	10518	8486	8133	8349	8935	9945	10908	13416	15621	17508	19276	19117
Capital Exp.	5947	7036	7145	7355	7749	8546	8948	10844	12420	13948	15474	15559
Working Capital Change	200	-200	0	0	0	0	0	0	0	0	0	0
Dividends	1100	1400	988	994	1186	1400	1960	2572	3201	3560	3802	3558
Debt Retirement	0	250	0	0	0	0	0	0	0	0	0	0
Total Application	7247	8486	8133	8349	8935	9945	10908	13416	15621	17508	19276	19117

Interest Expense

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Open	21000	19000	18513	20014	21758	23054	24414	24819	25349	25477	25573	25896
New	2000	-237	1501	1744	1296	1360	405	530	128	96	322	49
Retired	0	250	0	0	0	0	0	0	0	0	0	0
Year-end	19000	18513	20014	21758	23054	24414	24819	25349	25477	25573	25896	25945
Rate	7.5%	7.5%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
Interest Expense	1500	1407	1348	1462	1568	1661	1723	1756	1779	1787	1801	1814

Source: PowerWest

APPENDIX VII INVESTMENT ECONOMICS

INVESTMENT ECONOMICS METHODOLOGY

The full cycle economics of exploring for oil and gas reserves in Alberta under various prices and finding and development (F&D) costs were evaluated utilizing our reference reserve models. Our analysis of investment economics is based on a rigorous evaluation methodology. The basis of our approach is the use of discounted after tax cash flow valuation of oil and gas reserves produced from average or reference reservoirs.

The assumptions used in generating the investment economics are summarized as follows:

General

- Reference oil and gas reservoir and production characteristics were determined from Alberta Energy Resources Conservation Board (ERCB) data to reflect average or typical reserves for a single well oil and gas pool discovery.
- Oil and gas prices used were the Chenery Dobson low and high forecasts provided in Appendix VI and discussed in Section IV of the report.
- No provision was made for ARTC, as the reserves were assumed incremental to an above limit company.

Investment Scenario

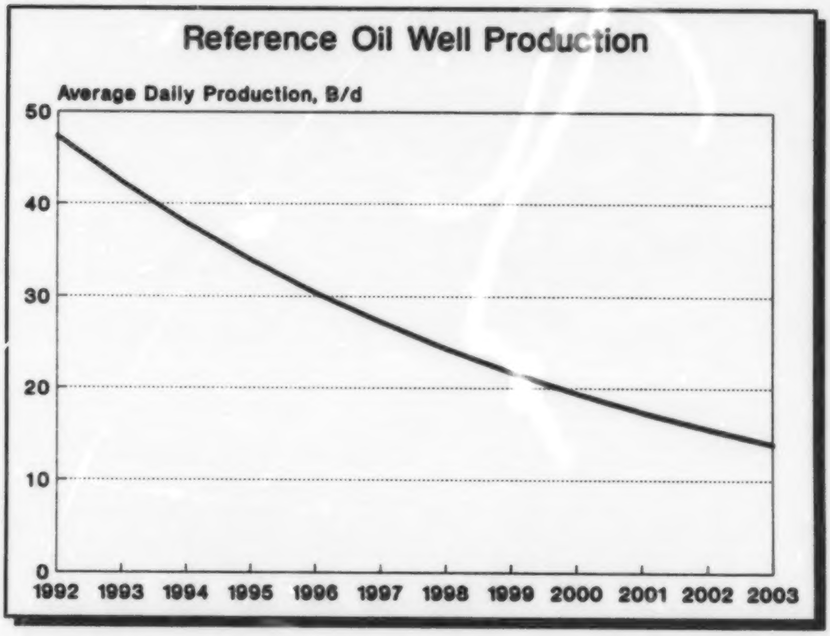
- A range of full cycle investment scenarios was determined by multiplying the reference model reserves by the relevant F&D costs. For tax purposes, the investments were allocated based on historical breakdowns derived from aggregate CPA data. Taxes were calculated on a stand alone basis, assuming income was sheltered only to the extent of reducing current taxes to zero.
- For oil, the expenditure breakdown was exploration (CEE) 30%, land (COGPE) 20%, development drilling (CDE) 30% and facilities and equipment (CCA Class 41) 20%. For gas, the expenditure breakdown was exploration (CEE) 25%, land (COGPE) 15%, development drilling (CDE) 30%, plants (CCA Class 29) 20%, and gathering plus field equipment (CCA Class 41) 10%. Theoretically, this approach embodies an element of risk weighting as F&D costs consider all expenditures, regardless of success.
- To accurately represent investment economics within the corporate sphere, we included a G&A component. We utilize average G&A costs of $1.65/BOE as determined from PMA industry data, reduced by 50% to $0.82/BOE to reflect the incremental G&A burden generated and supported by new investment.

Reserve and Production Assumptions

The following assumptions were used in creating the oil reference reserves model:

- Investment is made in 1991 with one well drilled, completed and tied in.
- Initial production of 50 B/d starting in January 1992, based on ERCB information.
- Decline rate of 10.5% per year.
- Proved developed producing pool of 156,000 B.
- 9 year reserve life index.
- New oil for royalty purposes.
- $2.00/B production costs with fixed costs of $1,500/well/month.
- $3.00/B average quality and transportation to Edmonton city gate.
- Inflation of 5% per year.

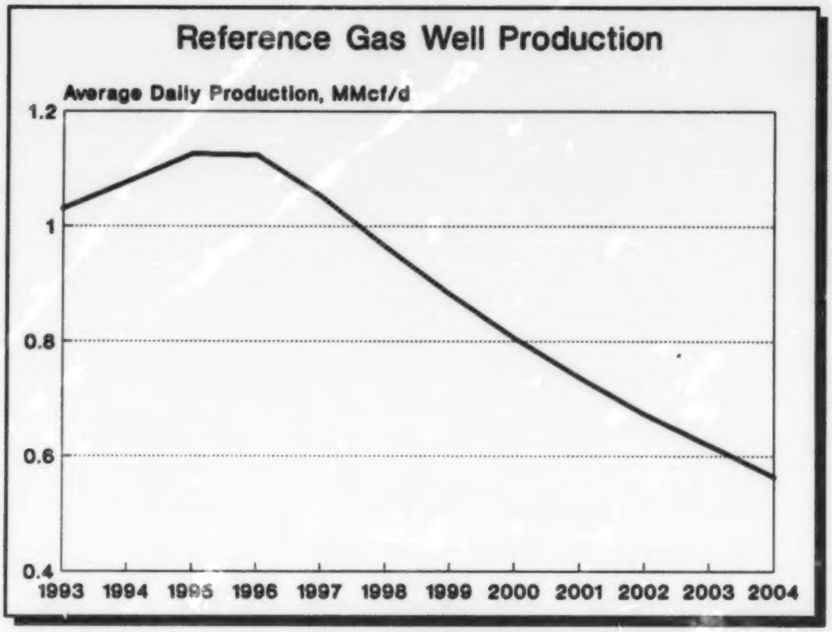
Figure APP VII.1



The following assumptions were used in creating the gas reference reserve model:

- One well was drilled and completed in 1991, plant and tie-in costs were incurred in 1992.
- Initial Production of 1 MMcf/d starting in January 1993.
- Production grows at 4.5% per year up to early 1995 as takes improve.
- Production declines at 8.5% per year starting in 1997.
- Proved developed producing pool of 5 Bcf.
- 13.6 year reserve life index consistent with ERCB data on max supply capability.
- New gas for royalty purposes.
- Variable operating costs of $0.35/Mcf and fixed costs of $2,500/well/month.
- Inflation of 5% per year.

Figure APP VII.2



This approach is somewhat simplistic as there are in reality no "typical" reservoirs in western Canada. Exploration targets vary significantly for both oil and gas and are dependent upon many factors, key of which are geography (location, transportation infrastructure) and geology (formation, depth). However, using actual data to develop an average reservoir is useful in establishing a point of reference for industry expectations. We believe our methodology allows us to accurately reflect the general level of returns that are associated with different F&D costs.

The key results of this analysis of investment economics are presented in Section IV of the report.

APPENDIX VIII

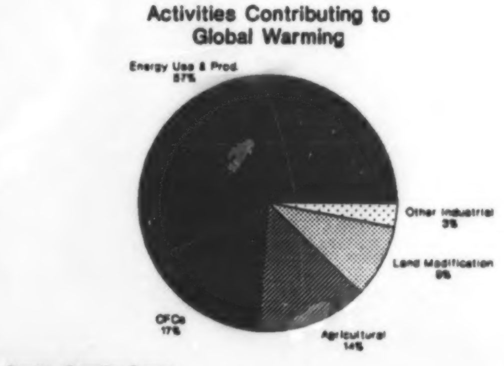
ENERGY AND THE ENVIRONMENT – IMPLICATIONS FOR THE OIL AND GAS SECTOR

THE SOURCES OF CONCERN

The production and consumption of energy has many potentially adverse effects on the environment. Large tracts of land are temporarily, sometimes permanently, disturbed by the mining of coal and uranium, and by large oil and gas developments, oil sands plants, and refining and petrochemical plants. There are also environmental impacts at the processing and transportation stages of the energy chain. The greatest source of concern, however, relates to the combustion of fossil fuels which produces significant emissions of sulphur oxides (SO_2), nitrogen oxides (NO_X), carbon dioxide (CO_2), and volatile organic compounds (VOCs). Emissions of these compounds causes three major pollutive effects.

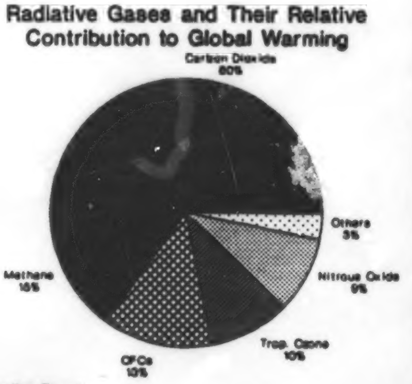
- *Global Warming*. Scientific research has identified several greenhouse gases--mainly water vapour, CO_2, methane, NO_X, chloro-fluorocarbons (CFCs)--which absorb heat that radiates from the earth's surface, holding in the heat and warming the climate. While there is a significant amount of debate ongoing as to the severity of the problem, the consensus appears to be that increasing concentrations of greenhouse gases will increase world temperatures, possibly by 1.5-4.5° C over the next 50 years. Energy production and consumption is estimated to be responsible for roughly 60% of the greenhouse gases emitted. CO_2 is the most important man-made greenhouse gas, with a relative contribution of about 50% to the global warming problem. NO_X emissions account for about 10% of the problem.

- *Acid Rain*. Emissions of SO_2 and NO_X are the principal causes of acid rain, a potential serious, long-term air pollution problem for industrialized countries. It increases the acidity of lakes, streams, ground water, and soil, threatening wildlife populations and reducing growth in forest as well as agricultural



Activities Contributing to Global Warming

Source: Canadian Energy Research Institute



Radiative Gases and Their Relative Contribution to Global Warming

Source: Canadian Energy Research Institute products. Acid rain is a regional as distinct from a global problem. It can, however, be carried long distances. Canada's acid rain problem is considerably worsened by the fact that the nature of wind patterns in North America leads to the "import" of considerable SO_2 from U.S. sources.

- *"Urban Smog"*. Urban smog, technically known as ground level ozone, is produced in the lower atmosphere by reactions involving NO_X and VOCs. Because the chemical reactions depend on both sunlight and temperature, ozone concentrations tend to be highest on hot sunny days. Over half of the Canadian population is regularly exposed to ground level concentrations of ozone known to have adverse health affects. Urban smog is also more of a regional than a global problem, although it is experienced in nearly every large city. As is the case for acid rain, however, emissions from south of the border contribute significantly to the Canadian problem, particularly in southern Ontario and Quebec.

Initiatives Taken to Deal With These Issues

The solution to environmental problems may seem obvious, regulate appropriate standards and then enforce them, but there are immense practical problems. The major difficulties are in setting the appropriate environmental standards, and establishing the legislative, regulatory and market framework that can achieve these standards at costs that will not jeopardize future economic growth, and that will not place any one sector of the economy at a competitive disadvantage in the international marketplace.

The problem of controlling CO_2 emissions is particularly intractable because it is truly international in scope, and because the magnitude of the problem and the severity of the solution are so poorly understood. To date, there has been lots of talk on the issue. General goals have been set but few concrete steps have been taken. One common point of agreement is that to be sustainable and economically efficient, pollution protection must be internationally coordinated and use market mechanisms. Two mechanisms have received considerable attention, a "carbon" tax on fossil fuels to reduce CO_2 emissions--opposed by the U.S.--and tradable permits--opposed by most countries but supported by the U.S.

Controlling acid rain and urban smog is much more readily achievable because they are regional issues with localized technological solutions. Canada already has put into place three broad programs to deal with these two issues (among others).

- A draft management plan for control of NO_X and VOC emissions has been developed, released for public review early last year. The draft plan contained 61 initiatives designed to achieve a targeted level of reductions, implementation of which will be shared by federal, provincial and municipal jurisdictions.

- The Canadian Acid Rain Control Program is focused on the seven eastern provinces and has, under federal-provincial agreements, adapted targets to reduce combined SO_2 emissions in 1994 to roughly one-half of 1980 levels.

- Canada's Green Plan strategy, formally released in December 1990, essentially ties the above two programs (and other initiatives) into a longer-term perspective. The plan committed the federal government to $3 billion over five years in new funding for the environment and sets out more than 100 initiatives.

> Acid rain emissions beyond 1994 will be capped by extended federal provincial agreements and a national emissions cap for SO_2 was established for the year 2000. The Global Environmental Security component of the plan allocated $575 million to stabilize CO_2 emissions.

Perhaps the most significant step taken to date has been the enactment of the U.S. Clean Air Act last November. The two key elements of the act are as follows:

- Acid rain-causing SO_2 emissions from electric utilities are to be cut in half from 1980 levels by the year 2000, a reduction of 10 million tons/year. This goal will be met in two phases. Phase I sets targets that 110 existing power plants are expected to meet by 1995. Phase II, which begins in 2000, implements much tighter standards on a nationwide basis, essentially placing a cap on overall emissions. Power generators will be issued allowances which will be tradable on the open market.

- Cities will be required to comply with current air quality standards for ozone, carbon monoxide and other pollutants. About 100 cities are now far from compliance. The law is designed to reduce pollution from vehicles by 40% in the next two years. It mandates the use of reformulated gasoline in increasing quantities over the next decade to meet targeted reductions in NO_X and VOCs. In addition, it requires that centrally fueled fleets of more than 9 vehicles in 26 urban areas be alternative fueled by 1998.

Implications for the Future

It is very difficult to quantify the impact of recently enacted legislation in Canada and the U.S., let alone the impact of new initiatives that are now being discussed and considered on an international basis. Nevertheless, it is clear that the environmental movement is building momentum and that it will have an impact on the oil and gas industry. This impact is likely to become much more apparent over the second half of the 1990's and into the 21st century, and has the following implications for the oil and gas industry.

1. Renewed emphasis will be placed on energy conservation.

2. Higher taxes will be imposed on energy consumption.

3. Alternative fuels will gain market share in the transportation sector.

4. Tighter specifications will be imposed on petroleum products, particularly with regard to sulphur content.

5. The price of petroleum products will increase to reflect the higher cost of refining "green" products.

6. Higher taxes, refining costs and mandated conservation will lead to slower growth in the petroleum demand of the OECD countries.

7. The above effects will tend to place downward pressure on the prices that producers receive at the wellhead.

8. Stricter product standards and the move to "green" fuels will tend to increase

the differentials between light and heavy/sour grades of crude oil.

9. Natural gas demand will be higher than otherwise would be the case. Incremental growth will occur in the electricity generation and transportation sectors.

10. Environmentally based gas demand will put upward pressure on gas prices.

11. The imposition of increasingly strict environmental standards leads to potentially dramatic higher costs. For instance, while reducing sulphur emissions at sour gas plants from 80% to 95% is fairly simple, achievable at a reasonable cost, and has tangible benefits, the step from 95% to 99.9% removal is much more expensive and the benefits are correspondingly smaller.

12. The regulatory burden and costs associated with getting larger scale projects through the environmental impact assessment process will increase.

13. Waste management and decommissioning costs have the potential to escalate dramatically. Companies now have a long-term liability for the waste they produce. Stricter standards will make it more difficult to handle waste water and limitations on flaring natural gas are potentially very costly. As older wells come to the end of their economic lives, abandonment costs will also become significant.

14. Canadian producers are price takers for both oil and gas. As such, higher costs from complying with stricter environmental standards will very difficult to pass through to consumers unless they are equally borne by U.S. competitors.

From a market and financial perspective the implications of environmental policy initiatives are unfortunately generally negative for the oil and gas sector. The result will be lower petroleum demand than would otherwise occur and downward pressure on oil prices. Widening oil quality price differentials will hurt oil producers. An increased regulatory burden and higher costs are also clear negatives for industry profitability. The bright spot is higher demand and longer-term higher prices for natural gas.